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EXPERIENCES GAINED IN IMPLEMENTING A BROAD-BASED RISK-INFORMED APPLICATION AFFECTING PUMP AND VALVE TESTING

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ABSTRACT

The South Texas Project was granted a first-of-kind exemption from special treatment requirements contained in 10CFR Parts 21, 50, and 100 in August 2001. Since that time, South Texas has pursued a cautious, deliberate approach to implement these risk-informed exemption allowances. Over the past two years, South Texas has gained a unique insight into the challenges and benefits that exist in pursuing a broad-based risk-informed application. The American nuclear industry is currently pursuing similar capabilities through proposed rule 10CFR 50.69* which is scheduled for NRC final review and approval in the July, 2004 timeframe. This proposed rule closely resembles the approach taken by South Texas in the exemption process and the allowances granted. For nuclear utilities that wish to pursue a similar broadbased risk-informed application, a well-conceived strategic approach is needed to prioritize the implementation activities as well as engage stakeholders in the implementation process. Cultural and communication challenges exist which must be addressed and effectively overcome.

The goal of this paper is to communicate these challenges to the attendees, inform attendees of the safety and economic benefits to be recognized through this risk-informed approach, and to provide insight into continuing application opportunities that were not readily apparent when the broad-based exemption was originally conceived. This paper and presentation will be beneficial for both domestic and international attendees, as well as for personnel with utility or regulatory backgrounds.

* Editor's Note: The NRC had not completed the development of 10 CFR 50.69 at the time of the preparation of this paper. Therefore, the discussion of the provisions of 10 CFR 50.69 in this paper should not be considered to represent the NRC final position on the rule.

INTRODUCTION

The South Texas Project (STP) is a two-unit Westinghouse four-loop PWR rated at 1270 MWe output. Unit 1 was placed in commercial operation in 1988, and Unit 2 was placed in commercial operation in 1989. The Station is owned by four separate entities, and managed by the South Texas Project Nuclear Operating Company (STPNOC). The Station is located about 85 miles southwest of Houston, Texas near the Texas Gulf Coast. Cooling water for the Station is drawn from an above-ground reservoir supplied by water from the nearby Colorado River. The design of the South Texas Project incorporates three safety trains; however, the Station is licensed such that all three safety trains must be available.

This paper discusses the blending of the STP Probabilistic Risk Assessment (PRA) Model with deterministic insights resulting in a variety of risk-informed applications. The application with broadest influence is the Exemption from Special Treatment Requirements, which was submitted as an Exemption Request to the Nuclear Regulatory Commission (NRC) in July 1999, and ultimately approved in August 2001. Since that time, STP has begun a cautious and deliberate implementation approach of these various Exemption allowances. This paper provides insights into the benefits and challenges noted in implementing a broad-based risk-informed application, with specific focus on pump and valve testing.

NOMENCLATURE

Probabilistic Risk Assessment Model – an engineering tool used for decision-making that models certain components within the plant design which influence the protection of the reactor core and the health and safety of the public. Risk-Informed Safety Classifications (RISC) – the segregation of categorized components into specific groupings. The four groupings identified in 10CFR 50.69 include:

- RISC-1 – safety-related, safety significant
- RISC-2 – non-safety related, safety significant
- RISC-3 – safety related, low safety significant
- RISC-4 – non-safety related, low safety significant

Special Treatment Requirements – the additional controls placed on safety-related equipment which exceed the normal controls placed on non-safety related equipment.

BACKGROUND

The South Texas Project (STP) has been actively involved with industry risk-informed applications since the 1980s. This involvement lead to the development of a robust Level 1 and Level 2 Probabilistic Risk Assessment (PRA) Model which has been foundational in the decision-making processes at STP. In November 1997, STP was granted a Graded Quality Assurance (GQA) Safety Evaluation Report, which permitted reduced assurances to be applied to components determined to be of low safety significance. During the initial implementation phases of this GQA allowance, it was determined that the regulatory Special Treatment Requirements contained within 10CFR Parts 21, 50, and 100 constrained STP to continue applying robust treatments to components determined to be low safety significant. This recognition resulted in a series of interactions with the Nuclear Regulatory Commission (NRC) to discuss potential approaches to address this regulatory constraint. In July 1999, STP submitted to the NRC a broad-based Exemption to exclude certain requirements of 10CFR Parts 21, 50, and 100 from those components determined to be Low Safety Significant or Non-Risk Significant. This Exemption approach was an industry first in that the request sought relief from broad process requirements rather than specific aspects of a specific rule.

In August 2001, following extensive discussions and interactions with the NRC, the *Exemption from Certain Special Treatment Requirements of 10CFR Parts 21, 50, and 100* was granted. This broad-based first-of-kind Exemption offered reductions in certain Special Treatment Requirements for the following regulations:

- 10CFR Part 21.3 – Reporting Requirements
- 10CFR 50.49(b) – Environmental Qualifications
- 10CFR 50.59 – Change Control
- 10CFR 50.55a(f), (g), (h)(2) – ISI/IST, ASME
- 10CFR 50.65 – Maintenance Rule
- Appendix B – Quality Controls
- Appendix J – Containment Leak Tightness
- 10CFR Part 100 – Seismic Requirements

The NRC viewed the South Texas Exemption as a proof-of-concept to permit other industry licensees to pursue similar reductions in special treatment requirements. Since the South Texas efforts preceded an industry approach, the STP effort was also viewed as a proto-type pilot for how the industry might proceed.

INDUSTRY'S APPROACH

In December 1998, the NRC issued SECY-98-0300, which identified three options that could be pursued in advancing broad risk-informed approaches. The three options offered were:

Option 1 – continue to allow licensees, on a case-by-case basis, to pursue individual risk-informed exemptions to existing rules. Under this option, there would be no broad industry-wide effort to either adjust the scope of the existing rules, or to risk-inform the rules themselves.

Option 2 – alter the *scope* to which the existing rules apply. For components determined to be low safety significant, these components could generally be removed from the scope of special treatment requirements and be subjected to normal commercial controls. Components determined to be safety significant would continue to be subjected to existing special treatment requirements. However, under this option, the existing rule language would not be changed.

Option 3 – revise the existing rule language to incorporate risk insights into the rules. This option was considered to be the final goal of a risk-informed environment, however, it was also recognized as being the most difficult to achieve in the short term.

Considering these three options, the NRC determined that an approach which combined Options 2 and 3 should be pursued. It was recommended that an Option 2 approach be pursued in the short-term, and in parallel, Option 3 should be pursued on certain specific rules.

The South Texas approach was deemed to be a proto-type pilot for the Option 2 approach. To codify a more generic industry approach which could be used by any domestic licensee, draft rule 10CFR 50.69 *'Risk-Informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors'* was generated and submitted for public review and comment in May 2003. The comment period closed in August 2003, and the NRC staff is currently working to resolve the received comments. The goal is to forward the draft rule to the NRC Commissioners in July 2004 for final review and action.

SCOPE OF DRAFT 50.69

The current scope of draft rule 10CFR 50.69 closely mirrors the South Texas Exemption scope. The rules to be addressed within 50.69 include the following:

- 10CFR Part 21
- 10CFR 50.49
- 10CFR 50.55a(f), (g), (h)
- 10CFR 50.55(e)
- 10CFR 50.65
- 10CFR 50.72
- 10CFR 50.73
- Appendix B
- Appendix J
- Appendix A to 10CFR Part 100

Draft 10CFR 50.69 is a voluntary rule which provides high level insights into the categorization and treatment approaches. To offer more detailed insight into the categorization and treatment implementation, the Nuclear Energy Institute (NEI) has drafted NEI-00-04 '*10CFR 50.69 SSC Categorization Guideline*'. In addition, the Electric Power Research Institute (EPRI) is drafting industry guidance for treatment of low safety significant components in the areas of environmental and seismic qualifications.

IT ALL BEGINS WITH CATEGORIZATION

Implementation of either the South Texas Exemption or the 10CFR 50.69 allowances require the categorization of components on a system-by-system basis. The categorization scheme created by STP, and generally mirrored by the 10CFR 50.69 approach, was reviewed and approved by the NRC. The STP approach relied upon probabilistic insights from STP's PRA Model blended with deterministic insights from a working-level Integrated Working Group (IWG). The Working Group consists of experts in the areas of PRA, Operations (a senior reactor operator), Licensing, Engineering, Quality, Operating Experience, Maintenance, and the associated System Engineer. The Working Group begins each system review by identifying all functions performed by the associated system. These functions are then categorized by asking a set of consistent questions which look at the influence of a specific function on initiating events, accident mitigation, the ability to fail other risk-significant systems, emergency operations, or mode changes/plant shutdown. The response to each of these questions is then weighted and summed to determine the final functional importance. Once completed, all components within the system are mapped to the functions that they support (a certain component may support a single function, or may support multiple functions). The Working Group then deliberates on the final component categorization considering the PRA categorization (if the component is modeled), component redundancy and diversity, operational history, and the knowledge/experience of the group. Using consensus decision-making criteria, a final categorization for each component is determined, the technical basis for the categorization documented, and the draft categorizations forwarded to a separate Expert Panel for review and approval.

The Expert Panel is made up of senior-level managers who are expert in the areas of PRA, Engineering, Licensing, Operations, and Maintenance. This Panel independently reviews the draft categorization input developed by the Working Group and deliberates on the satisfaction of the final results and the adequacy of the technical basis. If the Expert Panel concurs with the proposed categorization, the data is entered into the Station's electronic Master Equipment Database and becomes available for use by site personnel.

Only components that have been categorized are subject to the control adjustments stated in the Exemption. If a component has not yet been categorized, the treatments that were in place prior to the grant of the Exemption will remain in force.

STATUS OF THE STP CATEGORIZATION

As of March 18, 2004, South Texas had completed categorizations on 68 different system designators constituting over 70,000 individual components. The systems completed to date include those which would generally be considered as most crucial to safe reactor power operations. The categorized systems include:

- Reactor Coolant
- Safety Injection
- Auxiliary Feedwater
- Charging and Volume Control
- Emergency Diesel Generators
- Essential Cooling Water
- Main Steam
- Main Feedwater
- Component Cooling Water

Insight from the STP categorization effort to date identifies the following:

- Approximately 90% of all components categorized to date have been determined to be low safety significant (either RISC-3 or RISC-4 under the 10CFR 50.69 categorization approach)
- For safety-related components only, approximately 25% of these components are determined to be safety significant (RISC-1) while the remaining 75% are determined to be low safety significant (RISC-3)
- Less than 1% of the components have been determined to be non-safety related yet safety significant (RISC-2)

STP performs a periodic review to assess the continued acceptability of component categorizations on a once-per-18- month basis. The most recent periodic review was just completed in the first quarter of 2004. To date, STP has not identified any potential adverse performance trends as a result of applying reduced special treatment requirements.

CATEGORIZATION LESSONS LEARNED

The STP categorization process is proceduralized to ensure consistency in application. Beneficial insights, which have been identified to date, include the following:

1. *Be aware of potential critical changes* – changes to the PRA Model or possible performance declines in RISC-3 components can lead to a component crossing the threshold between low safety significant (RISC-3) into the safety significant area (RISC-1). Preventions must be put in place to anticipate these potential categorization changes, and a process must exist to quickly respond when an RISC-3 to RISC-1 transition occurs.
2. *Categorization changes are primarily driven by PRA Model changes* – to date, STP has not identified an adverse performance trend that has been due to the application of reduced treatments to RISC-3 components. However, due to the living nature of the PRA Model, when model revisions occur, an assessment of the model changes must be completed timely to understand the potential impacts onto the component categorization results.
3. *Creation of a 'buffer zone' is beneficial* – to heighten the awareness of borderline components that reside at the upper threshold of the RISC-3 box (however, are not significant enough to initially be placed in the RISC-1 box), STP created a buffer zone to assess these components during the initial categorization process and during follow-up reviews. This buffer zone (RAW between 1.8 and 2.0; Fussel-Vesely between 0.004 and 0.005) has been proceduralized to proactively consider potential categorization changes.
4. *Evaluate PRA-Modeled RISC-2 components early* – for safety significant, non-safety related components (RISC- 2) that are modeled in the PRA, however, have yet to undergo the component categorization process, these components should be evaluated for possible enhanced special treatment controls even before the final categorization is completed.
5. *Categorization guidance for electrical components and cabinets must be clear* – electrical component categorization requires unique guidance on breakers due to the potential impact on upstream safety significant components if the breaker fails to perform its function. In addition, instrumentation cabinets generally include many sub-components (i.e., fuses, relays, etc.) that may not be uniquely tagged as are pumps and valves. The

categorization of cabinets must factor in the functions performed by the sub-components contained within the cabinet.

6. *Excellent categorization stability has been noted* – using the South Texas approach to component categorization, very few categorization changes have been necessitated due to performance changes in components, PRA Model updates, or reassessment by Working Group members.

The above stated preventions have been note-worthy in achieving this stability.

7. *Consensus decision-making has worked well* – few dissenting opinions have been generated from the STP categorization process. When a dissenting opinion is noted, a process is in place to raise this issue to the Expert Panel for resolution.

8. *Application-specific categorizations can be used to better focus on component importance* – in addition to the broad- based categorizations performed by STP, application specific categorizations (e.g., for Risk-Informed In-Service Testing) can be developed and implemented. These specific categorizations focus on the application need (e.g., active testable functions performed by the component versus considering passive functions into the final importance determination). The hierarchy of the categorizations must be maintained with the application-specific categorizations remaining as a subset of the broad-based categorization approach. The application-specific categorization process is outside the scope of the STP Exemption or the approach to 10CFR 50.69.

9. *General Notes have aided the documentation basis* – each system generally consists of a number of support components (i.e., vent valves, drain valves, handswitches, etc.) which generally do not impact the ability of the major function to be satisfied. To aid in documenting the categorization bases for these support components, STP developed a series of General Notes which are consistently used from one system to another. The General Notes permit a short-hand means to document the categorization basis without repeating the same wording numerous times.

The categorization process has evolved, and continues to evolve, with the experiences gained at South Texas. Effective documentation of the categorization decisions and the bases that supports the categorization is of the utmost importance for future evaluation and validation of the adequacy of the existing component category.

IMPLEMENTING THE REDUCED TREATMENT ALLOWANCES

A sound and robust categorization process is necessary for effective implementation of the reduced treatment allowances provided by either the STP Exemption process or the industry's 10CFR 50.69 process. If the categorization process does not result in extreme high confidence that components have been properly 'bucketed' into one of the RISC-1, RISC-2, RISC-3, or RISC-4 boxes, then the confidence level in implementing the reduced treatment allowances will remain low and the implementation effort effectiveness will be hampered.

It is important to note again that only components which have gone through a categorization process are subjected to potential treatment changes. Any component, which has yet to be categorized, will remain under the current treatment requirements that are in force at the Station. For categorized components under either the STP

Exemption approach or the 10CFR 50.69 approach, the general treatment allowances are as follows:

RISC-1 Components – these are safety-related, safety significant components. The special treatment requirements currently imposed by regulatory requirements will remain, and no additional special treatments are necessary.

RISC-2 Components – these are non-safety related, safety significant components. These components generally are not under current regulatory special treatment requirements. The current performance of these components must be assessed to determine if additional controls should be applied. If the current performance does not meet expectations, then additional controls should be considered.

RISC-3 Components – these are safety-related, low safety significant components. These components are currently subjected to the same regulatory special treatment requirements imposed on RISC-1 components. RISC-3 components are candidates for reductions in special treatment controls per the allowances of 10CFR 50.69.

RISC-4 Components – these are non-safety related, low safety significant components. These components are generally not under current regulatory special treatment requirements, and do not require any additional controls to be applied. These components generally receive industrial-type controls.

STATUS OF THE STP IMPLEMENTATION ACTIVITIES

STP pursued a cautious, deliberate approach in implementing the treatment reduction allowances for RISC-3 components as provided in the STP Exemption.

Implementation of the Exemption allowances formally began in January 2002, and is continuing today. STP chose to focus on a limited number of programs that would provide both safety and economic benefit to the Station. The programs chosen, and the benefits noted, are generally as follows:

1. *Local Leak-rate Testing (LLRTs)* – RISC-3 components have been removed from the scope of LLRT testing based on being low safety significant and satisfying one or more of the following criteria:

   - The valve is open with mass flow during accident scenarios
   - The valve is closed in a closed water-filled system and is not required to change state in response to the accident
   - The valve is in a closed piping system which has a crush pressure greater than that of Containment
   - The valve is 1” in size or less

The LLRT Program and procedures have been modified to reflect the change in scope, and training provided to technicians and operators. The implementation has resulted in a 57% reduction in valves scoped for Type C Local Leak-rate Testing. It should be noted that the STP Exemption requested relief for Type C LLRT testing only, whereas the 10CFR 50.69 approach is seeking relief for both Type B and Type C LLRT testing.

2. *Maintenance Rule* – in cases where an entire system has been determined to be RISC-3 through the categorization process, the system can be removed from the scope of Maintenance Rule tracking and actions. To date, STP has removed 16 systems from the scope of the Maintenance Rule (the systems which previously caused the greatest number of Maintenance Rule actions were the Radiation Monitoring system and the Emergency DC Lighting system. Both of these systems were determined to be low safety significant, and have been removed from the scope of the Maintenance Rule through this process.). In addition, the other categorized systems have had their Maintenance Rule actions reduced since only safety significant components are required to be addressed. When systems/components are removed from the Maintenance Rule scope, STP relies on the Condition Reporting process to track and correct identified issues.

3. *Inservice Testing (IST)* – inservice testing of pumps and valves involves surveillance testing to provide periodic assurance that the component’s functional capabilities are validated. For RISC-3 components, these assurances do not require the same degree of rigor. STP has focused on extending the frequencies of RISC-3 components factoring in the component’s low safety significance and the performance history. Due to the large number of procedures impacted by removing the RISC-3 components from the IST Program, many of these components remain within the IST Program scope with extended test frequencies. The reasonable assurance basis used to justify the frequency extensions was documented and retained.

To date, STP has identified no increased failures due to the test frequency changes. Generally, the scope of valve stroke time testing has been reduced by about 25% due to the program changes.

In addition, STP is currently pursuing a Risk-Informed IST program request with the NRC to address those components remaining within the scope of IST (RISC-1 components). If the RI-IST Program is approved, an additional 178 valves and 7 pumps will be available for possible test frequency extensions. It is important to note that additional benefits are available to Stations that wish to pursue a RI-IST or RI-ISI program in addition to a 10CFR 50.69 approach only.

4. *Parts Procurement* – the STP procurement organization and spare parts engineering organization evaluate RISC-3 parts purchases on a case-by-case basis for potential usage of available industrial parts. In order to utilize an industrial part in an RISC-3 application, an engineering evaluation must be performed to document a basis for reasonable assurance that the industrial part will satisfy the safety-related functional requirements under design basis conditions. If the evaluation is satisfactory and the purchase of the industrial part is economically beneficial, then an industrial part can be procured. If the evaluation cannot successfully document a reasonable assurance basis, or there is little economic benefit in procuring an industrial part, then a safety-related, qualified part will be procured and installed. Generally, the price differential between a qualified part and an industrial part is a factor of three to five times higher. STP has identified certain instances where the price differential was greater than a factor of forty times higher to buy a qualified part versus an industrial part.

Examples of areas where industrial parts have been procured for RISC-3 applications include:

- Radiation monitor sample pumps
- Spent Fuel Pool Heat Exchanger discharge valve flow guides
- 1" vent and drain valves
- HVAC analog-to-digital flow controller changeouts
- Capacitors on computer card rebuilds

To date, STP is achieving approximately $250,000 per year in hard savings in the procurement area. Some areas which have hampered further procurement benefits have been associated with determining the proper level of reasonable assurance required for environmentally and/or seismically qualified parts. STP is working with EPRI to develop industry standards which can be utilized. In addition, the available safety-related, qualified stock in the warehouse must be depleted before additional possible industrial purchases are pursued. Also, in some cases, manufacturers are reluctant to sell industrial parts to their nuclear customers.

5. *Tool-Pouch Maintenance* – Tool-Pouch Maintenance (TPM) is a streamlined maintenance strategy that desires to utilize the skill-of-craft knowledge existing among the craft labor force, while reducing the burdensome documentation that generally accompanies task performance and completion. This approach generally results in no planned work instructions to complete a straight-forward task that the craftsman is skilled at performing (i.e., valve packing adjustments, flange leak tightening, etc.). Documentation of the task completion is maintained at a minimal level (computer based), and no paperwork is generated for long-term document retention. Document retention is accomplished by retaining the computer record only. Due to Appendix B requirements, the Tool-Pouch

Maintenance allowances were allowed only on non-safety related equipment prior to the grant of the STP Exemption. Upon approval of the Exemption, the TPM Guideline was revised to permit performance on safety-related RISC-3 components. Since that time, TPM performance has been tracking approximately 30% higher than historical performance. TPM performance permits a more timely correction of identified deficiencies, reduces the administrative burden on the low safety significant components, and permits more time to be focused on safety significant material deficiencies.

6. *Preventive Maintenance* – the scope and frequency of Preventive Maintenance (PM) activities have been altered by considering the safety significance of the associated component. In cases where the component is determined to be safety significant (RISC-1 or RISC-2), the PM activities have been evaluated for potential increases in scope or reductions in the periodicity between PM performances. In cases where the component is determined to be low safety significant (RISC-3), the scope may be reduced, but more likely, the PM frequency will be optimized considering the component performance history. Through the PM evaluation process, STP has identified averted cost savings of approximately $300,000 per year in labor, and approximately $60,000 per year in parts. These savings are realized each year for the remaining life of the Station.

STP's implementation activities have been hampered by several significant equipment issues during the initial two year effort (i.e., Steam Generator replacement in Unit 2 in October 2002, Unit 2 Main Turbine thrown blade in December 2002, Unit 1 Bottom-Mounted Instrument boron leak in April 2003, Unit 2 Emergency Diesel Generator thrown piston in December 2003). None of these equipment issues were a result of the Exemption implementation; however, each of these equipment issues has drawn both focus and resources away from the implementation efforts. However, the implementation activities continue to move forward deliberately and safely.

IMPLEMENTATION LESSONS LEARNED

The STP implementation process officially began in January 2002. Beneficial insights, which have been identified to date, include the following:

1. *Involve management early* – by nature of the Exemption process, STP had extensive management involvement early in the process due to this first-of-kind effort. It is imperative to initiate the implementation activities from a top-down approach. With management cognizant and supportive of the implementation requirements, the needed resources can be made available to support programmatic changes, and management can help influence the needed cultural changes within the organization. If management is not on board with the broad-based, risk-informed application, the rest of the organization will likely not follow, and the individual tasked with the implementation effort will be fighting a losing battle.

2. *Begin with a strong safety culture at the Station* – the first and foremost purpose of a broad-based risk-informed application is to enhance nuclear safety. If a sound safety culture does not currently exist at the Station, it would not be recommended for that Station to pursue broad risk-informed applications. A strong safety culture will help control the pace and quality of both the categorization and implementation efforts, and establish the parameters on how far the organization is comfortable and willing to move on the reasonable assurance scale. A strong safety culture will effectively push-back on efforts to move the implementation efforts too far, too fast.

3. *Using an Expert Panel helps pave the implementation pathway* – the currently proposed 10CFR 50.69 utilizes an Integrated Decision-making Panel (IDP) to perform the categorization of system functions and components. This IDP equates to the Working Group currently in place at STP. However, the 50.69 process does not require an independent, senior review panel to validate the categorization results and to provide management guidance to the IDP. STP has found the Expert Panel (made up of senior managers who are separate and distinct from the Working Group) to be an invaluable part of the categorization and implementation process. The Expert Panel provides a management backstop to the Working Group decisions by validating the soundness of the proposed categorizations. The Expert Panel addresses any dissenting opinions which arise during Working Group deliberations, and offer a management perspective on thepriorities and strategies for the Station to best pursue effective implementation. In addition, the Expert Panel serves as a springboard to communicate the capabilities of the Exemption allowances into the Station's organizations, and has the ability to hold their own resources accountable to accomplish the implementation tasks.

If an Expert Panel (or similar management structure) is not in place at a particular Station during the categorization process and during the implementation activities, it is likely that the IDP will be paralyzed by the lack of direct management support. In addition, a Station which undertakes a broad-based risk-informed application is pursuing a significant investment in resources with an anticipation of safety and economic returns. It is unlikely that any Station organization will turn this significant responsibility over to working level experts and expect them to solely determine the scope of plant components that will be subject to Special Treatment Requirements in the future.

4. *Have a plan* – implementing the allowances of a broadbased risk-informed application is not a quick undertaking. There are cultural issues to deal with, and as you probe into the depths of existing Station programs, there will be surprises found that must be addressed. All of these issues highlight one of the fundamental premises of change management: *have a plan*.

The developed plan must focus on the short-term milestones while maintaining a vision on the long-term objectives. The plan needs the involvement and concurrence of the various stakeholders that will be implementing the plan, as well as the review and approval of the management team that will be funding the plan's activities. The developed plan should be viewed as a living document, and should be periodically reviewed and updated with new statuses or newly recognized insights. The implementation plan developed by STP focused on those programmatic areas that were pursued in the short-term. A management sponsor of the implementation activities was identified and was periodically briefed by the stakeholders on the status of implementation actions. A stakeholder team was formed to discuss implementation challenges and to look for new opportunities.

5. *Maintain a cautious, deliberate approach* – the details of a 10CFR 50.69 implementation approach are complex and require that a sound bases for reasonable assurance be developed prior to reducing associated treatments. Personnel at the Station often don't realize or understand the criteria surrounding the approval of a 50.69 approach, and, without a plan, may attempt to pursue treatment reductions without the needed reasonable assurance or programmatic controls being in place. It is imperative that the developed plan be followed, and that this plan pursues a cautious, deliberate approach.

The developed plan must control the pace and quality of the implementation activities, and should offer opportunities for clear and critical feedback to be provided and factored into future actions and direction. A 50.69 implementation approach must focus on the long-term safe and reliable operation of the Station. The reason for pursuing 50.69 must not be to achieve some short-term economic fixes.

6. *Focus on areas that have both safety and economic benefits* – as the implementation plan is being developed, focus on opportunities that will enhance nuclear safety while at the same time offer economic benefits to the Station. While it may be desirable to focus initially on hard-dollar benefits in parts procurement and labor reductions, generally these savings will occur if the focus is shifted first toward programmatic nuclear safety enhancements. Nuclear safety enhancements are realized by shifting the focus of attention from the RISC-3 components and placing more focus on the RISC-1 components. The RISC-3 components are still expected to perform their design basis functions under accident conditions, howbeit at a lesser degree of

assurance. This lesser degree of assurance can be noted through reductions in testing requirements, reductions in inspection requirements, etc. As the burden demands are lessened in some of these programmatic areas, additional focus can then be placed on RISC-1 components and programmatic controls.

7. *Not all stakeholders will view this as a beneficial change* – up to this point in the history of commercial nuclear power, the operation of domestic reactors and safety systems have largely been controlled by deterministic regulations and programmatic controls. Even Station's with strong safety cultures and strong support for a 50.69 approach will have team members who are adverse to accepting the premise of risk-informed approaches and would prefer to maintain the deterministic bases that currently exist. If this deterministic individual is the programmatic owner of a process that you wish to risk inform, it is not suggested that this program would be your first choice to implement the 50.69 allowances.

Successful implementation comes in a series of small victories. Choose programmatic areas where the stakeholders are anxious to implement the 50.69 allowances, and are willing to expend the effort necessary to establish needed reasonable assurance bases and to modify programs and procedures. As small victories are claimed and burdens are reduced, others who were initially skeptical tend to become more accepting of the risk-informed environment.

8. *Understand your commitments* – STP added a new section to the Updated Final Safety Analysis Report (UFSAR) which captured the commitments for the approved Exemption. Since other domestic Stations will likely not pursue exemptions from the deterministic rules, but rather will pursue a license amendment under the 10CFR 50.69 approach, it is still important for the commitments to be clearly understood and captured prior to beginning your implementation activities. This process will require involvement of the Licensing personnel at the Station. In certain cases, if the approved 10CFR 50.69 wording is vague, the documentation of interpretations is important to establish a common basis of understanding. This may at times require the involvement of NRC personnel who supported the approval process.

When implementing a 50.69 approach, the vision must always be on the future and the defensibility of the actions being taken today. At some point in time, others will become responsible for the 50.69 implementation, and a clear paper trail should exist which documents the basis for actions previously taken.

9. *Implementation is not a one-year effort. It becomes part of your Station's long-term strategic plan* – when a Station pursues a broad-based risk-informed application, the Station is committing its long-term strategic plan to include the sound and deliberate implementation of the 50.69 allowances. This activity is a multi-year implementation effort, and will be a life-of-plant management responsibility. The Station decides on how quickly or slowly it wishes to pursue the implementation activities, but the license has been altered to factor in the 50.69 allowances. Therefore, the long-term vision must be clear when 10CFR 50.69 is chosen to be pursued.

CONCLUSION

As the industry's proto-type pilot for the 10CFR 50.69 activities, South Texas has gained a wealth of insights and experience in both the categorization activities and in the implementation activities. These insights point to the soundness of the risk-informed environment and its benefits in the decision-making processes at the Station. South Texas will continue to cautiously and deliberately pursue the full implementation of the Exemption allowances, and will be supportive of furthering industry's capabilities to pursue similar approaches.

RISK-INFORMING THE SPECIAL TREATMENT REQUIREMENTS OF THE NRC REGULATIONS

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U.S. Nuclear Regulatory Commission

Abstract

In Title 10 of the Code of Federal Regulations, the U.S. Nuclear Regulatory Commission (NRC) has established special treatment requirements for structures, systems, and components (SSCs) that perform safety functions at U.S. commercial nuclear power plants. These requirements address such aspects of SSC functional capability as environmental and seismic qualification, quality assurance, and inservice inspection and testing, and are based principally on deterministic considerations. The NRC is developing an alternative regulatory framework (proposed 10 CFR 50.69) that will allow the application of risk insights to determine appropriate treatment for plant SSCs in lieu of the current special treatment requirements. Implementation of this framework will provide flexibility in plant operation and design which can result in burden reduction without compromising safety.

I. INTRODUCTION

The regulations of the U.S. Nuclear Regulatory Commission (NRC) in Parts 21, 50, and 100 of Title 10 of the Code of Federal Regulations (10 CFR) contain special treatment requirements that impose controls to ensure the quality of SSCs that are within the scope of the regulations. Special treatment requirements are defined as those requirements that exceed normal commercial and industrial practices to provide a greater degree of confidence in the capability of SSCs to perform their safety functions under design-basis conditions throughout their service life. Special treatment requirements encompass such aspects as quality assurance, environmental and seismic qualification, inspection and testing, and performance monitoring.

The NRC has established an initiative to risk-inform the regulatory requirements for the treatment of SSCs used in nuclear power plants in the United States. As discussed in several Commission papers prepared by the NRC staff (e.g., SECY-99-256 and SECY-00-0194), Option 2 of this initiative involves categorizing plant SSCs based on their safety significance, and specifying the treatment that would provide an appropriate level of confidence in the capability of those SSCs to perform their design functions in accordance with their risk categorization. Under Option 2 of the NRC's risk-informed regulation initiative, RISC (risk-informed safety class)-1 SSCs are safety-related SSCs that perform safety-significant functions. RISC-2 SSCs are nonsafety-related SSCs that perform safety-significant functions.

RISC-3 SSCs are safety-related SSCs that perform low safety-significant functions on an individual basis. RISC-4 SSCs are nonsafety-related SSCs that perform low safety-significant functions. As described in SECY-98-300, the NRC staff expects there to be confidence that safety-related SSCs categorized as low risk-significant remain functional under design-basis conditions. Similarly, in SECY-00-194, the staff stated that nuclear power plant licensees will be required to maintain the functional capability of safety-related SSCs using existing or new programs.

II. PROOF-OF-CONCEPT EFFORT

On July 13, 1999, STP Nuclear Operating Company (STPNOC), licensee of the South Texas Project Units 1 and 2 nuclear power station, submitted a request under 10 CFR 50.12 for exemptions from the special treatment requirements of 10 CFR Parts 21, 50, and 100 for SSCs categorized at STP as low safety-significant (LSS) or non-risk significant (NRS) that are within the scope of these regulations. The NRC staff conducted the review of the STPNOC exemption request as a proof-of-concept effort for Option 2 of the risk-informed regulation initiative. In its submittal, the licensee requested approval of the exemptions primarily based on its categorization process that would allow the treatment of SSCs at STP according to their risk significance. Although relying heavily on STPNOC's categorization process in reaching the conclusions regarding the individual exemption requests, the staff recognized that

This paper was prepared by staff of the U.S. Nuclear Regulatory Commission. It may present information that does not currently represent an agreed-upon NRC staff position. NRC has neither approved nor disapproved the technical content.

the functionality of SSCs must be maintained consistent with the Option 2 approach, and to support the implicit assumption in the categorization process that SSCs will remain capable of performing their safety functions under design-basis conditions. The staff did not consider it necessary to maintain the same level of confidence in the functionality of low-risk SSCs as provided by the special treatment requirements. In assessing functionality, the staff's review focused on whether the programmatic elements of the licensee's treatment processes, if effectively implemented, could be sufficient for the exempted SSCs to remain capable of performing their safety functions under design-basis conditions. The staff determined that it was not necessary to assess the details regarding how the licensee will implement its treatment processes for safety-related LSS and NRS SSCs. On August 3, 2001, the staff granted STPNOC's request for exemptions from many of the special treatment requirements in the NRC regulations for safety-related LSS and NRS SSCs in consideration of the categorization and treatment processes to be applied at STP.

III. PROPOSED 10 CFR 50.69

Background

In SECY-02-176, the NRC staff presented proposed 10 CFR 50.69 to the Commission for risk informing the special treatment requirements in the NRC regulations. The Commission approved issuance of proposed 10 CFR 50.69 for public comment in a staff requirements memorandum (SRM) dated March 28, 2003. Proposed 10 CFR 50.69 was published for public comment in the Federal Register on May 16, 2003 (68 FR 26511).

In the Federal Register notice for the proposed rule, the Commission stated that it is important to note that this rulemaking effort, while intended to ensure that the scope of special treatment requirements imposed on SSCs is risk-informed, is not intended to allow for the elimination of SSC functional requirements, or to allow equipment that is required by the deterministic design basis to be removed from the facility (i.e., changes to the design of the facility must continue to meet the current requirements governing design change, most notably 10 CFR 50.59). Instead, the rulemaking should enable licensees and the NRC to focus their resources on SSCs that make a significant contribution to plant safety by restructuring the regulations to allow an alternative risk-informed approach to special treatment. Conversely, for SSCs that do not significantly contribute to plant safety, this approach should allow an acceptable, though reduced, level of assurance that these SSCs will satisfy functional requirements.

The Commission also stated that it was proposing to establish 10 CFR 50.69 as an alternative set of requirements whereby a licensee may undertake categorization of its SSCs using risk insights and adjust treatment requirements based upon their resulting significance. Under this approach, a licensee would be allowed to reduce special treatment requirements for SSCs that are determined to be of low safety significance and would revise requirements for treatment of other SSCs that are found to be safety significant. The proposed requirements would establish a process by which a licensee would categorize SSCs using a risk-informed process, adjust treatment requirements consistent with the relative significance of the SSC, and manage the process over the lifetime of the plant.

To implement these requirements, a risk-informed categorization process would be employed to determine the safety significance of SSCs and place the SSCs into one of four risk-informed safety class (RISC) categories. It is important that this categorization process be robust to enable the NRC to remove requirements for SSCs determined to be of low safety significance. The determination of safety significance would be performed by an integrated decision-making process which uses both risk insights and traditional engineering insights. The safety functions would include both the design basis functions (derived from the "safety-related" definition, which includes external events), as well as functions credited for severe accidents (including external events). Treatment requirements for the SSCs are applied as necessary to maintain functionality and reliability, and are a function of the category into which the SSC is categorized. Finally, assessment activities would be conducted to make adjustments to the categorization and treatment processes as needed so that SSCs continue to meet applicable requirements. The proposed rule also contained requirements for obtaining NRC approval of the categorization process and for maintaining plant records and reports.

Proposed Rule Requirements

§ 50.69 Risk-informed categorization and treatment of structures, systems and components for nuclear power reactors

(a) Definitions.

"Risk-Informed Safety Class (RISC)-1 structures, systems, and components (SSCs)" means safety-related SSCs that perform safety-significant functions.

"Risk-Informed Safety Class (RISC)-2 structures, systems and components (SSCs)" means nonsafety-related SSCs that perform safety-significant functions.

"Risk-Informed Safety Class (RISC)-3 structures, systems and components (SSCs)" means safety-related SSCs that perform low safety-significant functions.

"Risk-Informed Safety Class (RISC)-4 structures, systems and components (SSCs)" means nonsafety-related SSCs that perform low safety-significant functions.

"Safety-significant function" means a function whose degradation or loss could result in a significant adverse effect on defense-in-depth, safety margin, or risk.

(b) Applicability and scope of risk-informed treatment of SSCs and submittal/approval process.
(1) A holder of a license to operate a light water reactor (LWR) nuclear power plant under §§ 50.21(b) or 50.22, a holder of a renewed LWR license under Part 54 of this chapter; a person seeking a design certification under Part 52 of this chapter, or an applicant for a LWR license under § 50.22 or under Part 52, may voluntarily comply with the requirements in this section as an alternative to compliance with the following requirements for RISC-3 and RISC-4 SSCs:

(i) 10 CFR Part 21.

(ii) 10 CFR 50.49.

(iii) 10 CFR 50.55(e).

(iv) The inservice testing requirements in 10 CFR 50.55a(f); the inservice inspection, and repair and replacement, requirements for ASME Class 2 and Class 3 SSCs in 10 CFR 50.55a(g); and the electrical component quality and qualification requirements in section 4.3 and 4.4 of IEEE 279, and sections 5.3 and 5.4 of IEEE 603-1991, as incorporated by reference in 10 CFR 50.55a(h).

(v) 10 CFR 50.65, except for paragraph (a)(4).

(vi) 10 CFR 50.72.

(vii) 10 CFR 50.73.

(viii) Appendix B to 10 CFR Part 50.

(ix) The Type B and Type C leakage testing requirements in both Options A and B of Appendix J to 10 CFR Part 50, for penetrations and valves meeting the following criteria:

(A) Containment penetrations that are either 1-inch nominal size or less, or continuously pressurized.

(B) Containment isolation valves that meet one or more of the following criteria:

(1) The valve is required to be open under accident conditions to prevent or mitigate core damage events;

(2) The valve is normally closed and in a physically closed, water-filled system;

(3) The valve is in a physically closed system whose piping pressure rating exceeds the containment design pressure rating and that is not connected to the reactor coolant pressure boundary; or

(4) The valve is 1-inch nominal size or less.

(x) Appendix A to Part 100, sections VI(a)(1) and VI(a)(2), to the extent that these regulations require qualification testing and specific engineering methods to demonstrate that SSCs are designed to withstand the Safe Shutdown Earthquake and Operating Basis Earthquake.

(2) A licensee voluntarily choosing to implement this section shall submit an application for license amendment pursuant to § 50.90 that contains the following information:

(i) A description of the process for categorization of RISC-1, RISC-2, RISC-3 and RISC-4 SSCs.

(ii) A description of the measures taken to assure that the quality and level of detail of the systematic processes that evaluate the plant for internal and external events during normal operation, low power, and shutdown (including the plant-specific probabilistic risk assessment (PRA), margins-type approaches, or other systematic evaluation techniques used to evaluate severe accident vulnerabilities) are adequate for the categorization of SSCs.

(iii) Results of the PRA review process conducted to meet § 50.69 (c)(1)(i).

(iv) A description of, and basis for acceptability of, the evaluations to be conducted to satisfy § 50.69(c)(1)(iv). The evaluations shall include the effects of common cause interaction susceptibility, and the potential impacts from known degradation mechanisms for both active and passive functions, and address internally and externally initiated events and plant operating modes (e.g., full power and shutdown conditions).

(3) The Commission will approve a licensee's implementation of this section if it determines that the process for categorization of RISC-1, RISC-2, RISC-3, and RISC-4 SSCs satisfies the requirements of § 50.69(c) by issuing a license amendment approving the licensee's use of this section.

(4) An applicant for a license voluntarily choosing to implement this section shall include the information in § 50.69 (b)(2) as part of application for a license. The Commission will approve an applicant's implementation of

this section if it determines that the process for categorization of RISC-1, RISC-2, RISC-3, and RISC-4 SSCs satisfies the requirements of § 50.69(c).

(c) SSC Categorization Process.
(1) SSCs must be categorized as RISC-1, RISC-2, RISC-3, or RISC-4 SSCs using a categorization process that determines whether an SSC performs one or more safety-significant functions and identifies those functions. The process must:

(i) Consider results and insights from the plant-specific PRA. This PRA must at a minimum model severe accident scenarios resulting from internal initiating events occurring at full power operation. The PRA must be of sufficient quality and level of detail to support the categorization process, and must be subjected to a peer review process assessed against a standard or set of acceptance criteria that is endorsed by the NRC.

(ii) Determine SSC functional importance using an integrated, systematic process for addressing initiating events (internal and external), SSCs, and plant operating modes, including those not modeled in the plant-specific PRA. The functions to be identified and considered include design bases functions and functions credited for mitigation and prevention of severe accidents. All aspects of the integrated, systematic process used to characterize SSC importance must reasonably reflect the current plant configuration and operating practices, and applicable plant and industry operational experience.

(iii) Maintain the defense-in-depth philosophy.

(iv) Include evaluations that provide reasonable confidence that for SSCs categorized as RISC-3, sufficient safety margins are maintained and that any potential increases in core damage frequency (CDF) and large early release frequency (LERF) resulting from changes in treatment permitted by implementation of § 50.69(b)(1) and § 50.69(d)(2) are small.

(v) Be performed for entire systems and structures, not for selected components within a system or structure.

(2) The SSCs must be categorized by an Integrated Decision-making Panel (IDP) staffed with expert, plant-knowledgeable members whose expertise includes, at a minimum, PRA, safety analysis, plant operation, design engineering, and system engineering.

(d) Alternative treatment requirements.
(1) RISC-1 and RISC 2 SSCs. The licensee or applicant shall ensure that RISC-1 and RISC-2 SSCs perform their functions consistent with the categorization process assumptions by evaluating treatment being applied to these SSCs to ensure that it supports the key assumptions in the categorization process that relate to their assumed performance.

(2) RISC-3 SSCs. The licensee or applicant shall develop and implement processes to control the design; procurement; inspection, maintenance, testing, and surveillance; and corrective action for RISC-3 SSCs to provide reasonable confidence in the capability of RISC-3 SSCs to perform their safety-related functions under design basis conditions throughout their service life. The processes must meet the following requirements, as applicable:

(i) Design control. Design functional requirements and bases for RISC-3 SSCs must be maintained and controlled. RISC-3 SSCs must be capable of performing their safety-related functions including design requirements for environmental conditions (i.e., temperature and pressure, humidity, chemical effects, radiation and submergence) and effects (i.e., aging and synergism); and seismic conditions (design load combinations of normal and accident conditions with earthquake motions);

(ii) Procurement. Procured RISC-3 SSCs must satisfy their design requirements;

(iii) Maintenance, Inspection, Testing, and Surveillance. Periodic maintenance, inspection, testing, and surveillance activities must be established and conducted using prescribed acceptance criteria, and their results evaluated to determine that RISC-3 SSCs will remain capable of performing their safety-related functions under design basis conditions until the next scheduled activity; and

(iv) Corrective Action. Conditions that could prevent a RISC-3 SSC from performing its safety-related functions under design basis conditions must be identified, documented, and corrected in a timely manner.

(e) Feedback and process adjustment.
(1) RISC-1, RISC-2, RISC-3 and RISC-4 SSCs. In a timely manner but no longer than every 36 months, the licensee shall review changes to the plant, operational practices, applicable industry operational experience, and, as appropriate, update the PRA and SSC categorization.

(2) RISC-1 and RISC-2 SSCs. The licensee shall monitor the performance of RISC-1 and RISC-2 SSCs. The licensee shall make adjustments as necessary to either the categorization or treatment processes so that the categorization process and results are maintained valid.

(3) RISC-3 SSCs. The licensee shall consider data collected in § 50.69(d)(2)(iii) for RISC-3 SSCs to determine whether there are any adverse changes in performance such that the SSC unreliability values approach or exceed the values used

in the evaluations conducted to satisfy § 50.69 (c)(1)(iv). The licensee shall make adjustments as necessary to either the categorization or treatment processes so that the categorization process and results are maintained valid.

(f) Program documentation, change control and records.
(1) The licensee or applicant shall document the basis for its categorization of any SSC under paragraph (c) of this section before removing any requirements under § 50.69(b)(1) for those SSCs.

(2) Following implementation of this section, licensees and applicants shall update their final safety analysis report (FSAR) to reflect which systems have been categorized in accordance with § 50.71(e).

(3) When a licensee first implements this section for a SSC, changes to the FSAR for the implementation of the changes in accordance with § 50.69(d) need not include a supporting § 50.59 evaluation of the changes directly related to implementation. Thereafter, changes to the programs and procedures for implementation of § 50.69(d), as described in the FSAR, may be made if the requirements of this section and § 50.59 continue to be met.

(4) When a licensee first implements this section for a SSC, changes to the quality assurance plan for the implementation of the changes in accordance with § 50.69(d) need not include a supporting § 50.54(a) review of the changes directly related to implementation. Thereafter, changes to the programs and procedures for implementation of § 50.69(d), as described in the quality assurance plan may be made if the requirements of this section and § 50.54(a) continue to be met.

(g) Reporting. The licensee shall submit a licensee event report under § 50.73(b) for any event or condition that would have prevented RISC-1 or RISC-2 SSCs from performing a safety-significant function.

Public Comments

The NRC received 26 comment letters on the proposed rule. In addition, the NRC received feedback in response to several specific issues discussed in the proposed rule notice. A summary of the most significant of over 200 public comments on the proposed rule and feedback on specific issues is provided below:

1. Consideration of More Detailed Language for RISC-3 SSC Treatment Requirements.

   As discussed in the proposed rule notice, the Commission invited comment on whether more detailed rule language for RISC-3 treatment was necessary to provide reasonable confidence in RISC-3 design basis capability. For the most part, industry commenters asserted that there was no need for more detailed treatment requirements for RISC-3 SSCs in the rule. Comments from State organizations and public interest groups considered the proposed rule language to be inadequate to provide reasonable confidence in the capability of RISC-3 SSCs to perform their safety-related functions under design basis conditions. The public comments revealed a significant divergence in the interpretation of the proposed rule language by industry commenters from the expectations described in the SOC for the proposed rule.

2. PRA Requirements

   The Commission requested stakeholder comment on whether the NRC should amend the requirements in paragraph 10 CFR 50.69(c) to require a level 2 internal and external initiating events, all-mode, peer-reviewed PRA that must be submitted to, and reviewed by, the NRC. Stakeholder comments ranged from those supporting more extensive PRA requirements to those who conclude that the current PRA requirements in 10 CFR 50.69(c) are sufficient. The industry commenters stated that additional PRA requirements were not necessary. State organizations and public interest groups supported increased PRA requirements.

3. Review and Approval of RISC-3 Treatment

   The Commission requested stakeholder comment on whether the NRC should review and approve the RISC-3 treatment processes being developed by the licensee or applicant prior to implementation in addition to reviewing the categorization process. Public interest groups and comments from State organizations generally stressed the need for the NRC to review and approve RISC-3 treatment processes in advance of implementation to confirm appropriate treatment will be applied to RISC-3 SSCs given that these SSCs are safety-related. On the other hand, industry commenters did not consider prior review and approval of RISC-3 treatment to be necessary in light of the low safety significance of individual RISC-3 SSCs, other requirements that help maintain safety, and the availability of inspection and enforcement by the NRC.

4. Inspection and Enforcement

The Commission requested stakeholder comment on whether or not changes are needed in the NRC's reactor oversight process, including the inspection and enforcement program, to enable NRC to exercise the appropriate degree of regulatory oversight of these aspects of facility operation with regard to 10 CFR 50.69. The public comments on the proposed rule indicated general support for providing regulatory oversight of the implementation of processes established under 10 CFR 50.69 through the NRC's inspection and enforcement process. Some stakeholders considered the current inspection and enforcement process to be sufficient without adjustment. Other stakeholders recommended that the NRC consider additional training and guidance to inspectors to support implementation of 10 CFR 50.69.

5. Operating Experience

The Commission requested stakeholder feedback regarding the role that relevant operational experience could play in reducing the uncertainty associated with the effects of treatment on performance and specifically sought public comment as to what information might be available and how it could be used to support implementation of this rulemaking. Some stakeholders commented that relevant operating experience argues against the removal of special treatment requirements and that regulatory attention should be increased for this equipment. Other stakeholders suggested that there is a large amount of data that demonstrates that commercial and safety-related SSCs have comparable failure rates with the implication that special treatment requirements can be removed with little impact. Other stakeholders commented that there are already opportunities for industry to share experience data with existing industry and regulatory programs implying that a new program is not necessary.

6. SOC Guidance

Numerous comments were received from the industry regarding the nature of the information in the proposed rule's SOC supporting both 10 CFR 50.69(c) and (d)(2). Several industry commenters stated that the discussion in the SOC was inconsistent with the rule requirements. For example, some commenters suggested that, contrary to the SOC discussion, the treatment requirements for RISC-3 SSCs in 10 CFR 50.69(d)(2) would allow exercising of pumps and valves as a means of providing reasonable confidence in the design basis capability of those components. Another commenter claimed that, contrary to the SOC discussion, 10 CFR 50.69 would allow the leakage tests required by 10 CFR Part 50, Appendix J, for containment isolation valves to be eliminated without considering the capability of those valves to close under design basis conditions. Other commenters asserted that the corrective action process alone would be sufficient to satisfy the high-level requirements for feedback and monitoring of RISC-3 SSCs in 10 CFR 50.69.

7. RISC-3 Treatment Requirements

Numerous stakeholder comments were received concerning the 10 CFR 50.69(d)(2) requirements for RISC-3 SSCs. Some public stakeholders provided their view that the RISC-3 treatment requirements were inadequate in light of previous industry experience (e.g., regarding the use of substandard parts) and that more detailed RISC-3 requirements are needed to address common cause failures, significant degradation, and in general to avoid an increase in risk to the health and safety of the public. Industry stakeholders tended to view the RISC-3 requirements as too prescriptive and beyond what is necessary to maintain reasonable confidence of RISC-3 SSC design basis capability. Some of the industry comments revealed that the rule requirements might not be implemented consistent with the NRC's expectations discussed in the SOC.

8. Seismic Experience Data

Several industry commenters stated that the SOC for the proposed rule might create additional burden on plants licensed prior to implementation of Appendix A to 10 CFR Part 100. Industry commenters also raised concerns regarding the SOC discussion on use of seismic experience data. Some commenters implied that it would be acceptable to use "experience data" alone to have reasonable confidence that an SSC is capable of functioning during an earthquake even if there is no actual "experience data" for the SSC.

9. Feedback

Several industry commenters requested adjustments to the feedback requirements in 10 CFR 50.69(e)(1) to provide more efficient implementation of the rule. For example, one commenter suggested that the maximum time interval for updating the categorization and treatment processes be modified from 36 months to two refueling outages.

10. Basis for RISC-3 SSC Reliability

A number of comments were received regarding the technical basis for the RISC-3 SSC reliability (failure rates) to be used in the risk sensitivity study performed under 10 CFR 50.69(c)(1)(iv) to demonstrate reasonable confidence that any potential risk increase from implementation of the rule is maintained acceptably small. Some commenters suggested that licensees or applicants that voluntarily implement the rule should be required to characterize and reasonably bound the specific effects of eliminating treatment on SSC reliability under design basis and severe accident conditions. Other commenters suggested that there is evidence that reductions in treatment (using industry practices) have no impact on SSC reliability.

11. Crediting SSCs

    A number of industry commenters indicated that statements in the SOC specifically obligated a licensee implementing 10 CFR 50.69 to evaluate treatment applied to all safety significant SSCs to ensure adequacy of treatment and cited this as an added burden that is neither necessary nor appropriate because RISC-1 SSCs are already subjected to full regulatory requirements. Another commenter stated that the additional performance conditions (beyond what is assumed in the design basis) to address PRA performance assumptions should not be subject to 10 CFR 50, Appendix B, requirements that remain for RISC-1 SSCs and indicated that the design control documentation necessary to capture the assumptions made in the categorization process will place a large implementation cost on plants. Another commenter recognized that, while RISC-1 SSCs performing beyond design basis functions and RISC-2 SSCs may require additional special treatment requirements to be applied, they interpreted the NRC intent in the SOC as requiring all safety significant SSCs (RISC-1 and RISC-2) to be subjected to enhanced regulatory control.

12. Adequate Protection

    The staff received several comments indicating that the proposed regulation would not maintain adequate protection of public health and safety. The public comments on proposed 50.69 revealed divergent interpretations of the high-level requirements for the treatment of RISC-3 SSCs in 10 CFR 50.69.

13. License Amendment

    Some stakeholders commented that the proposed requirement to prepare, submit, and then receive approval of a license amendment in order to implement 10 CFR 50.69 is a disincentive to its use. It was commented that, in light of the desire to move to a more performance-based regulatory regime, voluntary implementation of 10 CFR 50.69 should be developed by licensees using the requirements in the rule and any attendant regulatory guidance, with routine NRC inspection serving to verify acceptable compliance.

Review of Public Comments

At the time of preparing this paper, the NRC staff was reviewing public comments on proposed 10 CFR 50.69 for resolution. The schedule provides a goal of completing the review of public comments and preparing a final rule later in 2004.

IV. CONCLUSIONS

The NRC regulations specify special treatment requirements for SSCs that perform safety functions at U.S. commercial nuclear power plants. These requirements address such aspects of SSC functional capability as environmental and seismic qualification, quality assurance, and inservice inspection and testing, and are based principally on deterministic considerations. The NRC prepared proposed 10 CFR 50.69 that would allow the application of risk insights to determine appropriate treatment for plant SSCs in lieu of the current special treatment requirements. The NRC staff is reviewing public comments on proposed 10 CFR 50.69 with publication of the rule anticipated later in 2004. If implemented effectively, the rule will allow NRC and licensee to focus their resources for the treatment of SSCs commensurate with their importance to health and safety. It will provide flexibility in plant operation and design which can result in burden reduction without compromising safety. The risk-informed regulation initiative and the STP exemption review reflect the NRC's ongoing efforts to incorporate risk insights into the regulation of nuclear power plants.

V. REFERENCES

Federal Register, 68 FR 26511, "Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors," May 16, 2003.

Letter dated August 3, 2001, to William T. Cottle, STPNOC, from John A. Zwolinski, NRC, regarding South Texas Project, Units 1 and 2 - Safety Evaluation on Exemption Requests from Special Treatment Requirements of 10 CFR Parts 21, 50, and 100.

SECY-98-300 (December 23, 1998), "Options for Risk-Informed Revisions to 10 CFR Part 50 - Domestic Licensing of Production and Utilization Facilities."

SECY-99-256 (October 29, 1999), "Rulemaking Plan for Risk-Informing Special Treatment Requirements."

SECY-00-0194 (September 7, 2000), "Risk-Informing Special Treatment Requirements."

SECY-02-176 (September 30, 2002), "Proposed Rulemaking to Add New Section 10 CFR 50.69, 'Risk-Informed Categorization and Treatment of Structures, Systems, and Components.'"

Increased Component Reliability Utilizing Risk Insight and Refined Maintenance Optimization (RMO) Approaches

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Abstract

Equipment reliability is – "The assurance that the function of structures, systems, trains and components will perform upon demand and sustain their function for their intended design mission time." Reliability included in the original plant design is sustained over the plant life by the integration of Preventive Maintenance (PM) and Predictive Maintenance (PdM) strategies with appropriate inspection and test technologies.

The Sargent & Lundy (S&L) Refined Maintenance Optimization (RMO) process focuses on the criticality of components using a risk insight approach and a more refined optimization of maintenance requirements. The Refined Maintenance Optimization is aimed at improving plant component reliability and reducing overall maintenance costs. The RMO process is a more focused and detailed approach that is the next step beyond the industry template driven approaches. It is not a "cookie cutter" approach and it requires more detailed and analytical engineering evaluations using an integrated multi-talented team and extensive repository of testing data. The RMO approach complements and adds considerable value to plant maintenance optimization (MO) programs.

The RMO process utilizes innovative techniques to cost effectively optimize maintenance tasks and frequencies. By utilizing "Refined Maintenance Optimization" approach, the plant owner is able to:

- Reduce overall maintenance costs while improving equipment reliability.
- Show quick payback on RMO investment.
- Achieve significant economies of scale for similar component types in other plant systems through leveraging RMO project results.
- Potentially reduce dose.

Background

Over the past several years, a number of industry initiatives have been implemented to formulate acceptable approaches for determining criticality of components. In this regard, the American Society of Mechanical Engineers (ASME), Electric Power Research Institute (EPRI), Institute of Nuclear Power Operations (INPO), and various industry users groups have published papers and guidelines to provide users with the necessary guidance to properly categorize and determine criticality of components. Most of these approaches utilize risk insight approaches. The primary reasons for this effort can be summarized as follows:

- Identification of critical components will ensure that, from a safety and reliability perspective, engineering, maintenance, and operation resources can be focused on the right components to maintain reliable plant operation.
- Effective maintenance strategies can be formulated and implemented for critical components based on the degree of component criticality. In other words, maintenance strategies for critical components would differ from those components that are categorized as non-critical components.

Once the criticality of components has been determined, the next step is to develop the most effective maintenance strategies for critical and non-critical components. The maintenance strategies will depend on many factors including the criticality of components. A number of plants use the techniques published by EPRI, INPO, and various users groups, while others have developed their own techniques to support maintenance optimization effort. The common thread in these approaches is the use of varying criteria, some risk and other non-risk based, to first determine the criticality of components and then move forward with maintenance optimization.

This paper presents an acceptable approach and proven technique to determine the criticality of components using a risk insight approach. It also introduces a unique process to optimize current maintenance requirements and frequencies. This unique maintenance optimization approach is known as Refined Maintenance Optimization.

Methodology for Risk Informed Categorization

Nuclear power plants have developed plant specific Probability Risk Assessment (PRA) models that incorporate several major components. However, these PRA models usually do not address all components subject to risk. Because of this, the industry has developed various techniques to identify critical components based on risk. Several plants have reviewed the application of various risk-based component categorization techniques and found them to be expansive in scope and not economically feasible. The method documented in this paper provides a cost-effective approach for categorizing valves. This approach can be easily expanded, modified, and streamlined to determine criticality of other components in the plant.

Figure 1 provides an overview of risk-based approach to categorize valves. The determination of valve category will employ system's risk significance data as documented in the station's Maintenance Rule (MRule) program. Utilizing MRule data will ensure consistency between the valve and MRule programs as it pertains to risk informed ranking of structures, systems, and components (SSCs). The approach presented in Figure 1 provides a structured and systematic method for categorizing valves which will achieve the following:

- Determination of critical valves based on safety classification, functional requirements, MRule risk significance, and economics.
- Focusing of resources for performance of valve design bases, testing, and maintenance activities as defined by the station valve programs.
- Identification of scope of valves for maintenance optimization effort.

Refined Maintenance Optimization (RMO) Approach

The objective of current industry and regulatory initiatives is to ensure safe plant performance (i.e., improve plant performance and reliability) and reduce/control operating and maintenance costs to remain competitive. To achieve these objectives, systematic techniques and cost effective methods are needed to:

- Identify critical systems and components.
- Focus engineering, maintenance, and financial resources on the right systems and components.
- Develop and implement cost-effective maintenance strategies.
- Prioritize engineering and maintenance activities by implementing maintenance strategies on the right components.
- Migrate from unplanned maintenance to planned maintenance.
- Establish measurable performance indicators.

Although several industry initiatives have produced a number of documents to perform risk informed categorization of components, not much has been published in the past several years for maintenance optimization. Most utilities have some type of a maintenance optimization program in place. Typically, these maintenance optimization programs were developed based on guidelines established by the industry and utility users group. It is our experience that the results achieved through implementation of these industry guidelines result in conservative preventive maintenance (PM) and predictive maintenance (PdM) requirements and frequencies resulting in:

- Many maintenance tasks and additional maintenance burden (i.e., costs).
- Deferral of PMs with limited bases and minimal justification.
- Increase in maintenance backlog.

The Refined Maintenance Optimization (RMO) process goes beyond the current industry template driven maintenance optimization approach and reduces maintenance costs while improving equipment reliability. RMO is built around a unique set of processes, technologies, and people; and each of these attributes are briefly summarized as follows:

The Process

A unique process and implementing procedure is developed that improves work efficiency and ensures a consistent level of quality that meets or exceeds industry and plant specific requirements. The RMO process is aimed at improving plant equipment reliability and reducing overall maintenance costs. Several plants have realized favorable results using this approach. Figures 2 and 3 show the overall RMO process.

The Technologies

Existing industry and plant-specific component test data is leveraged to support the RMO process and obtain meaningful results. The repository of this data acquired over the past two decades is used to quickly produce quantifiable results with sound technical bases.

The People

Effective execution of RMO projects requires a focused, integrated, and multi-talented team of individuals with system, component, maintenance, and aging management experience. Use of an integrated team allows the process to be effective by leveraging and utilizing the project team's core competencies. This integrated team will also bring multi-industry best practices to the table.

The following case studies are presented that demonstrate the success and significant benefits from employing the RMO approach:

Case Study 1: Diaphragm Valve Project (Categorization & RMO)

RESULT OF RISK BASED VALVE CATEGORIZATION	
Category 1: High Safety Significant	59
Category 2: Low Safety Significant	86
Category 3: Economically Significant	187
Category 4: Others	726
Total	**1058**

PLANNED MAINTENANCE COST					
Frequency	Number of PMs	X	Total Number of PMs	Average* Cost/PM	Total Cost
4 Years	59**	5	295	$5,700	$1,681,500
Current Planned Level of Effort:					**$ 1,681,500**

* Maintenance labor/parts cost. Does not include work planning and associated costs.

** Scope of project was for 59 category 1 valves.

RMO PROJECT INVESTMENT	
Actual cost of performing the RMO project	**$60,000**

REVISED PLANNED MAINTENANCE COST WITH TECHNICAL BASES					
Frequency	Number of PMs	X	Total Number of PMs	Average Cost/PM	Total Cost
3 Years	1	6	6	$5,700	$34,200
10 Years	5	2	10		$57,000
20 Years	38	1	38		$216,600
30 Years	15	1	15		$85,500
Revised Planned Level of Effort:					**$ 393,300**

CUMULATIVE COST AND SAVINGS	
Current Planned Level of Effort	$1,681,500
RMO Project Investment	($60,000)
Revised Planned Maintenance Cost Using S&L Refined Approach	($393,300)
SAVINGS	**$1,228,200**

SIMPLE PAYBACK ANALYSIS			
PLANNED		REVISED PLANNED	
Cumulative:	$1,681,500	Cumulative:	$393,300
Annual:	$84,075	Annual:	$19,665
Savings/Year		$64,400	
Required Investment		$60,000	
Payback		**< 1 Year**	

Case Study 2: Air Operated Valve (AOV) Project (Categorization)

RESULT OF RISK BASED VALVE CATEGORIZATION	
Category 1: High Safety Significant	66
Category 2: Low Safety Significant	609
Category 3: Economically Significant	113
Category 4: Others	624
Total	**1412**

Case Study 3: Air Operated Valve (AOV) Project (RMO)

System: Bleed Steam				Total Number of AOVs: 169	
CURRENT PLANNED MAINTENANCE COST					
Frequency	Number of PMs	X	Total Number of PMs	Average Cost/PM	Total Cost
Planned Valve Assembly Overhauls:					
6 Years	29	4	116	$6,900	$800,400
12 Years	140	2	280	$6,900	$1,932,000
Planned Actuator Assembly Overhauls:					
6 Years	168-29=139	2	278	$4,100	$1,139,800
				Current Planned Level of Effort:	**$3,872,200**
* Maintenance labor/parts cost. Does not include work planning and associated costs.					

RMO PROJECT INVESTMENT	
Cost of performing the RMO project	**$75,000**

PROJECTED PLANNED MAINTENANCE COST	
Diagnostic Testing	$245,000
Valve Assembly Overhauls	$62,000
Actuator Assembly Overhauls	$177,000
Total	**$484,000**

CUMULATIVE COSTS AND SAVINGS	
Current Planned Level of Effort	$3,872,000
MO Project Implementation Cost (Investment)	($75,000)
Projected Planned Maintenance Cost Using S&L Refined Approach	($484,000)
SAVINGS	**$3,313,000**

SIMPLE PAYBACK ANALYSIS			
CURRENT PLANNED		PROJECTED PLANNED	
Cumulative:	$3,872,000	Cumulative:	$484,000
Annual:	$161,000	Annual:	$20,200
Savings/Year		$140,800	
Required Investment		$75,000	
Payback		**≅ 6 Months**	

Conclusion

Significant benefits can be realized from utilizing risk insight and RMO approaches. As the case studies demonstrate, RMO projects can successfully reduce the plant's overall maintenance costs and improve component reliability. It is expected that the following benefits will be realized from implementing an RMO project:

Quantitative

- Reduced Overall Maintenance Cost
- Reduced Maintenance Labor Burden
- Material/Parts Procurement Cost Reduction
- Potential Dose Reduction
- Potential Reduction of Outage Tasks

Qualitative

- Documented Bases
- Increased Reliability (INPO AP-913)
- Reduced Scheduling & Planning
- Reduced Likelihood of Error
- Proper Identification of all PM Tasks and Intervals.

Figure 1
Risk Insight Categorization Flowchart

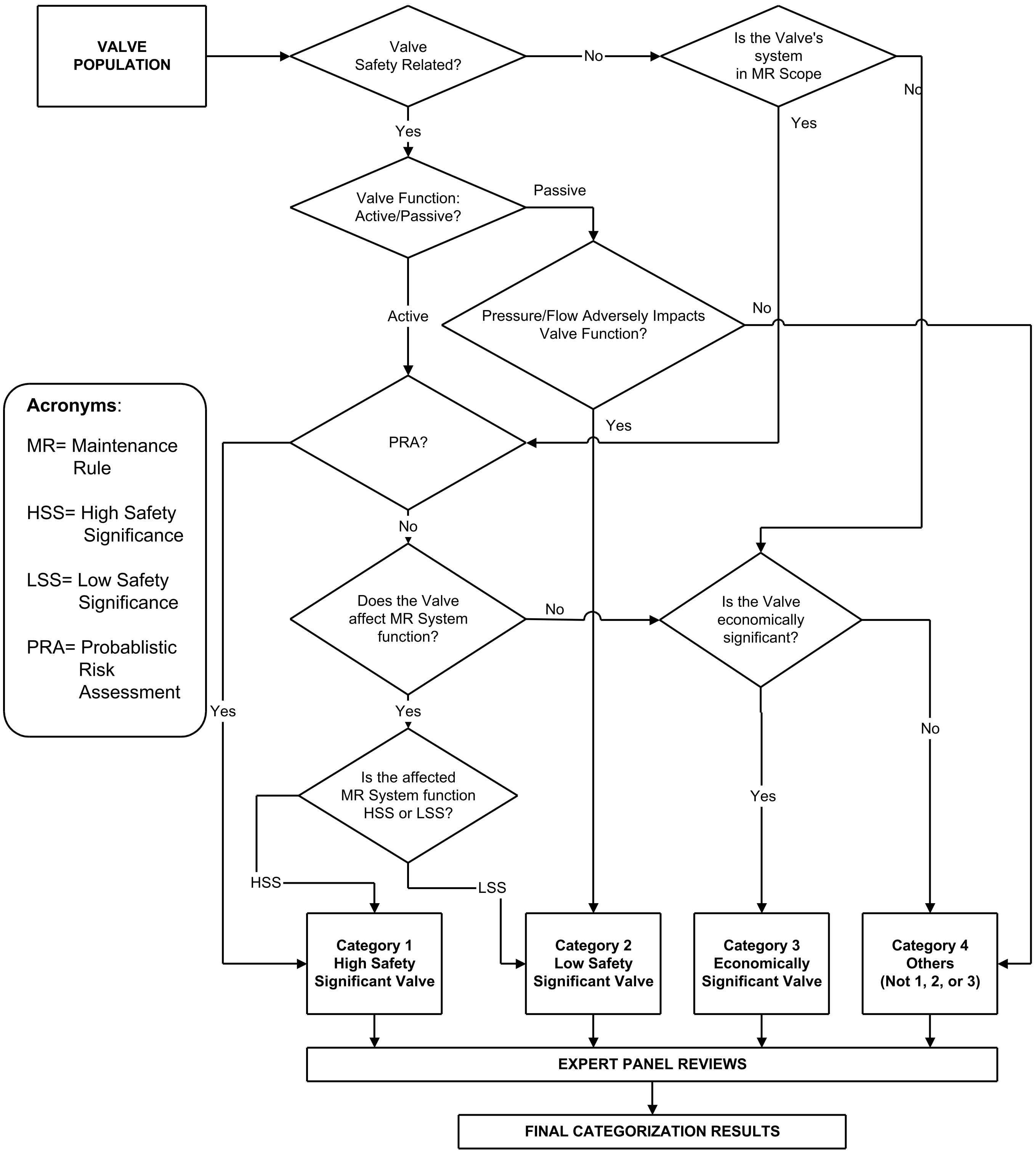


Figure 2
Refined Maintenance Optimization
Bubble Chart

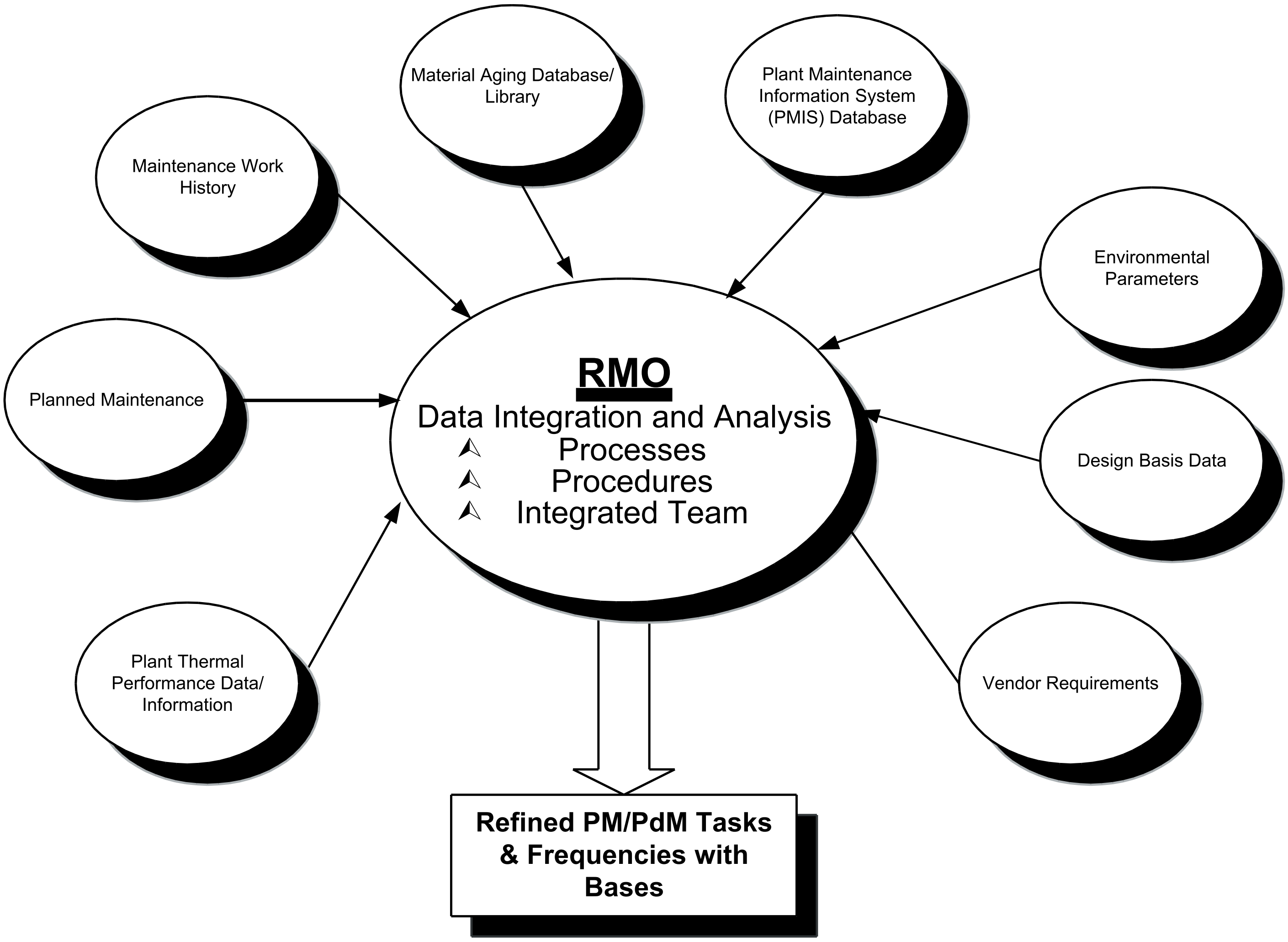
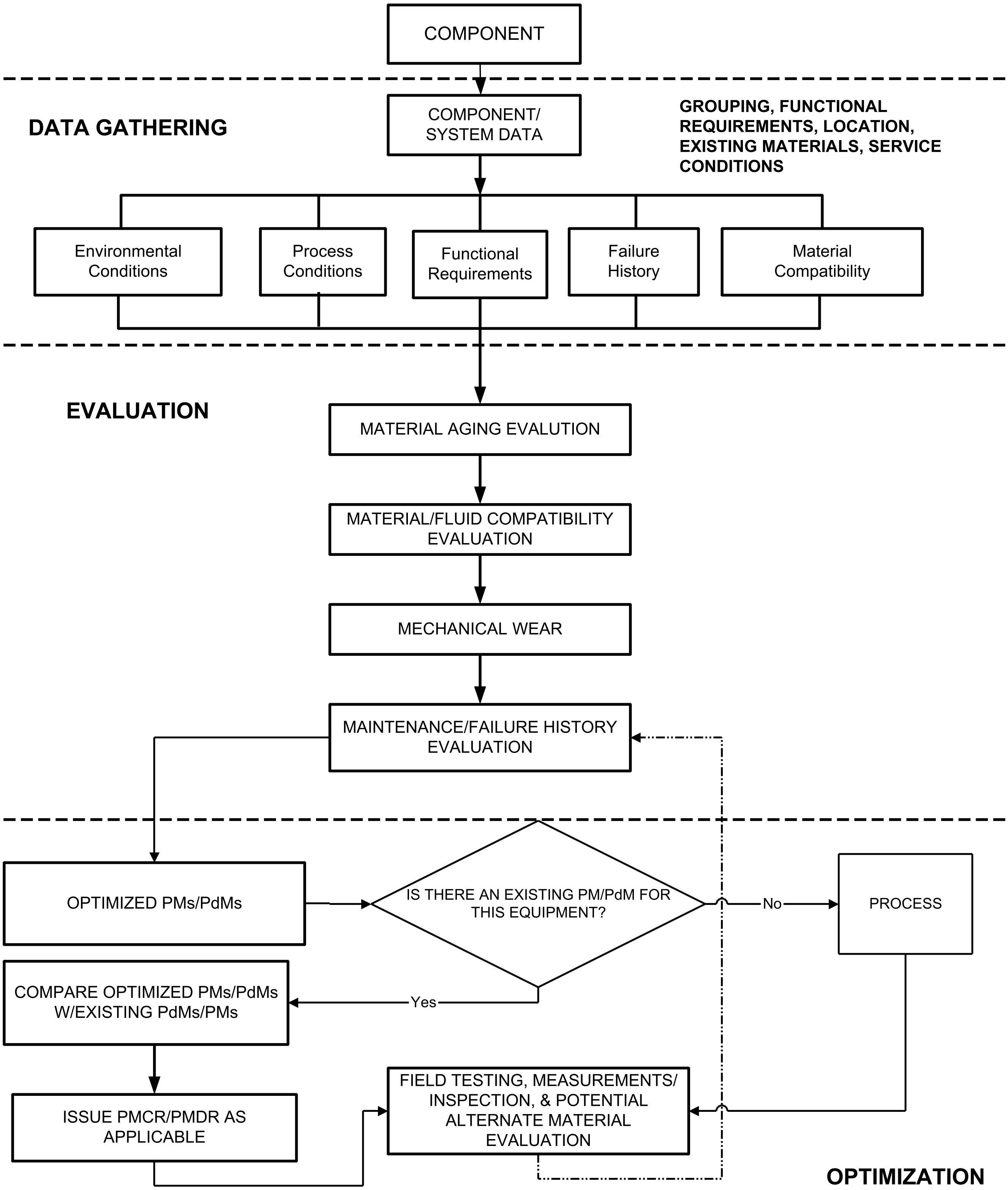


Figure 3
RMO Process Flowchart



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Proposed ASME OM Code Subsection ISTE – A Presentation of the Concepts of Component Testing

Craig D. Sellers

Alion Science and Technology

Abstract

Proposed Subsection ISTE of the American Society of Mechanical Engineers (ASME) *Code for Operation and Maintenance of Nuclear Power Plants* (OM Code) provides mandatory requirements for owners who voluntarily elect to implement a risk-informed inservice testing (IST) Program. The proposed Subsection was prepared by combining the component categorization requirements and methodology from Code Case OMN-3 with high-level inservice test requirements for components developed on philosophies from Code Case OMN-1 (performance-based testing for motor-operated valves) and OM Code Appendix II (check valve condition monitoring).

The proposed test strategies for High Safety Significant Component (HSSC) Pumps and Power-Operated Valves are derived the performance-based testing philosophy of Code Case OMN-1 (performance-based testing for motor-operated valves). The performance-based test philosophy of OMN-1 is presented in a non-prescriptive fashion providing flexibility allowing the owner to determine appropriate parameters for monitoring and trending on a component, or component group basis. The proposed test strategy for Low Safety Significant Component (LSSC) components is specified as non-diagnostic exercising on a frequent basis supplemented by performance monitoring, diagnostic examination to verify design basis capability on an infrequent basis, and a requirement to maintain component reliability.

This paper presents the concept of Code Case OMN-1 performance-based testing for motor-operated valves (MOVs) and its application to other HSSC power-operated components. It also describes the expansion of OM Code Condition Monitoring requirements beyond check valves and presents the basis for LSSC test requirements.

1.0 INTRODUCTION

Proposed Subsection ISTE provides mandatory requirements for owners who voluntarily elect to implement a risk-informed inservice testing (IST) Program. The proposed Subsection was prepared by combining the component categorization requirements and methodology from Code Case OMN-3, *Requirements for Safety Significance Categorization of Components Using Risk Insights for Inservice Testing of LWR Power Plants*,[1] with high-level inservice test requirements for components developed on philosophies from Code Case OMN-1, *Alternative Rules for Preservice and Inservice Testing of Certain Electric Motor-Operated Valve Assemblies in Light-Water Reactor Plants OM Code-1995, Subsection ISTC*,[2] and OM Code Appendix II, *Check Valve Condition Monitoring Program*.[3]

A basic tenant of risk-informed inservice testing is to focus activities and resources on High Safety Significant Components (HSSCs) while reducing efforts on Low Safety Significant Components (LSSCs). Baseline IST requirements are those of the current OM Code. Applying this risk-informed tenant to IST requirements, one would increase OM Code test requirements for HSSCs and decrease OM Code test requirements for LSSCs. The proposed Code Case was developed on this basis.

The proposed test strategies for HSSC pumps and power-operated valves are derived the performance-based testing philosophy of Code Case OMN-1.[2] The performance-based test philosophy of OMN-1, in which test frequency is based on the margin between observed performance and required performance, is capable of identifying and trending degradation that could lead to component failure. This is consistent with the requirements of Code Case OMN-3,[1] and represents increased test requirements to those in the current OM Code.

The proposed test strategy for HSSC self-actuated valves is to place the valves in a condition monitoring program consistent with OM Code Appendix II, *Check Valve Condition Monitoring Program*.[3] Condition monitoring programs implement inservice activities capable of identifying and trending degradation that could lead to component failure which is also consistent with the requirements of Code Case OMN-3,[1] and represents increased test requirements to those in the current OM Code.

The proposed test strategy for LSSC components is specified as non-diagnostic exercising on a frequent basis supplemented by performance monitoring, diagnostic examination to verify design basis capability of power-operated components on an infrequent basis, and a requirement to maintain component reliability. These inservice test activities combined provide confidence in component operational readiness and represent a decrease in test requirements to those in the current OM Code.

2.0 HSSC Test Requirements

The proposed test strategy for HSSC self-actuated valves is to place the valves in a condition monitoring program consistent with OM Code Appendix II.(3) The requirements from OM Code Appendix II were placed verbatim into the proposed ISTE except that the term "check valve" was replace with "valve" to expand applicability to additional self-actuated valves such as relief valves. Additionally, the Appendix II requirements on grouping and documentation were incorporated into those specific sections of ISTE.

The proposed test strategies for HSSC pumps and power-operated valves are derived the performance-based testing philosophy of Code Case OMN-1.(2) OMN-1 describes a methodology for performance-based testing of electric motor-operated valves in which the available valve stem torque is compared to the required stem torque and the functional margin determined. (Valve performance parameters other than stem torque, such as stem thrust, are allowed.) The required test interval is determined based on analysis of time-related changes in functional margin. An example determination of test interval is shown in ***Figure 1***.

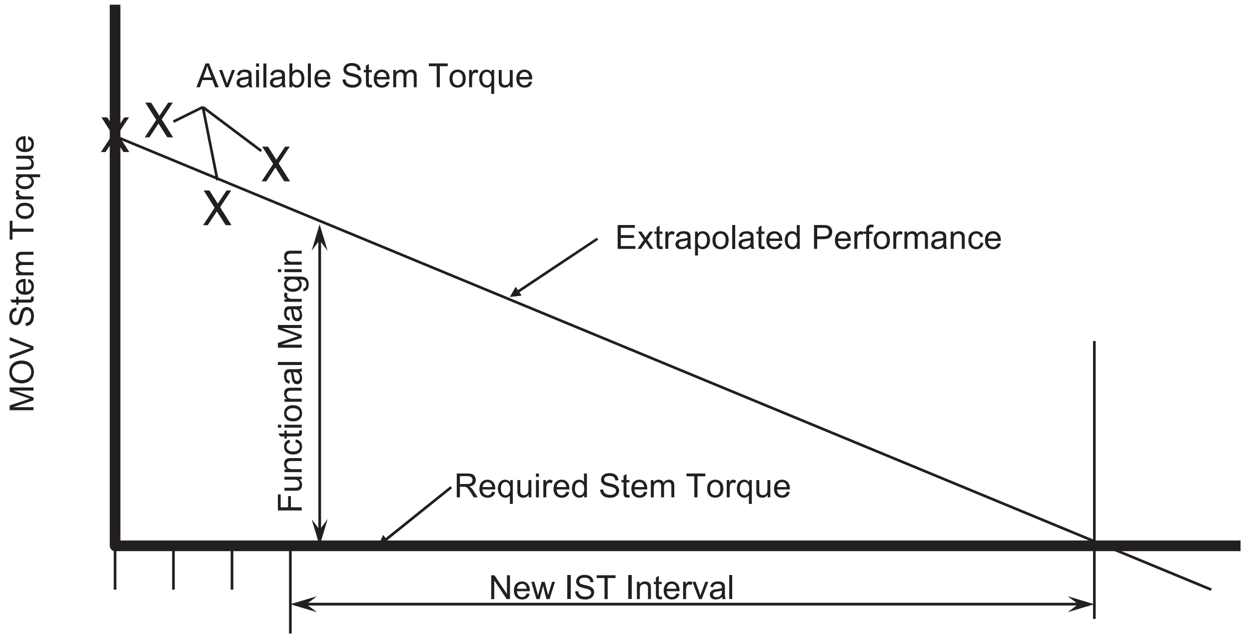
Code Case OMN-1 describes multiple methods for determining required and available stem torque including analytical means if justified.

Proposed ISTE takes this general methodology for determining test interval based on functional margin, expands it to include the concept of limit margin, and applies it to all pumps and power-operated valves. Rather than specifying specific parameters to use in assessing performance margins, proposed ISTE requires the owner to specify and justify the selected parameters.

1.1 High-Level Requirements

Two options were considered for applying OMN-1 requirements to components other than MOVs. One option was to add prescriptive requirements for the additional components and the other was to remove prescriptive MOV requirements.

Figure 1
Example Determination of Test Interval



The option chosen was to remove the prescriptive requirements applicable to MOVs and develop high-level requirements that can be applied to all power-actuated components. The basis for this choice was two-fold. First, owners implementing risk-informed programs will be making major changes to the way they do business and having to develop new programs for structure, system, and component treatment. Imposing prescriptive requirements would hinder this process. Second, adding prescriptive requirements would fail to address new component designs, possibly fail to address all current components, and significantly expand the volume of the subsection.

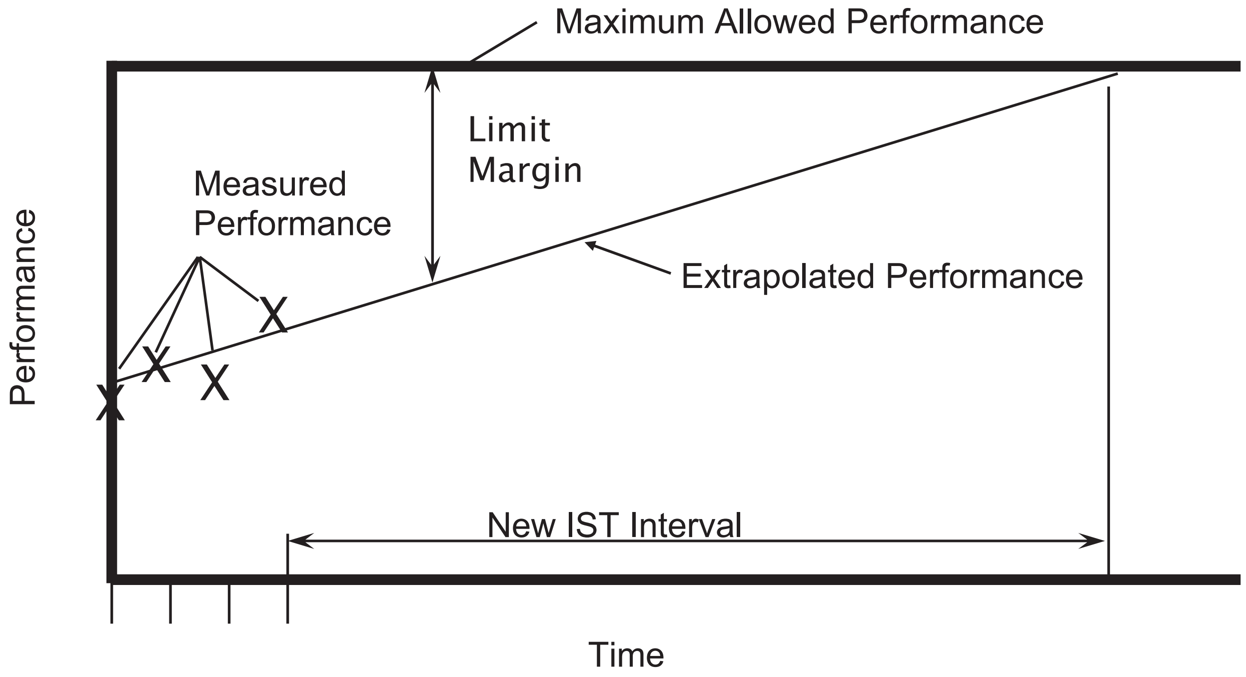
Additionally, while OMN-1 specifies prescriptive requirements for determining required and available MOV stem torque based on testing at design basis conditions, it also allows the use of alternative analytical methods with justification. Prescriptive requirements for these analytical methods and justification of the methods are not provided. In developing the proposed ISTE, the decision was made to exclude prescriptive requirements for determining required and available performance parameters in lieu of specific requirements for the owner to select and justify appropriate parameters.

1.2 Limit Margin

The concept of limit margin is introduced in the proposed ISTE and has been the subject of many comments. Functional margin is defined as the increment by which a component's available capability exceeds the capability required to operate under design basis conditions. This definition is derived from the Code Case OMN-1 definition of MOV functional margin. Proposed ISTE defines limit margin as the increment by which a component's maximum allowable performance exceeds the observed performance.

Limit margin is very similar to functional margin; the difference being functional margin compares observed performance to required performance while limit margin compares observed performance to allowable performance. Functional margin typically assesses performance parameters where reduction in performance is of primary concern, such as stem torque, stroke time, pump flow, and pump developed head. Limit margin assesses performance parameters where increase in performance is of primary concern, such as stem thrust, bearing vibration, and lubricant contamination. An example determination of test interval based on limit margin is shown in ***Figure 2***.

Figure 2
Example Determination of Test Interval Based on Limit Margin



1.3 Acceptance Criteria

Proposed ISTE specifies the use of acceptance criteria where ISTB and ISTC use reference values. The acceptance criteria required by ISTE are identical to reference values in ISTB and ISTC except that individual parameters are not specified.

Example performance parameters for use as acceptance criteria in the determination of functional and limit margins include:

Component	Functional Parameter	Limit Parameter
MOVs:	Required Stem Thrust Required Stem Torque	Allowable Stem Thrust Allowable Stem Torque Allowable Motor Torque
Air-Operated Valves (AOVs):	Required Stem Thrust Required Spring Force	Allowable Stem Thrust Allowable Packing Load Allowable Spring Relaxation
Hydraulic-Operated Valves (HOVs):	Required Stem Thrust Required Spring Force	Allowable Stem Thrust Allowable Packing Load
Solenoid-Operated Valves (SOVs):	Required Stroke Time Required Coil Saturation Time	Allowable Coil Current
Pumps:	Discharge Pressure Required Flow Rate	Allowable Vibration Allowable Lube Contamination

3.0 LSSC Inservice Test Requirements

The proposed test requirements for LSSC pumps and power-operated valves are exercising on a refueling interval and design basis capability verification on a 10-year interval. Proposed test requirements for LSSC self-actuated valves are exercising on a refueling interval for check valves and either exercising or replacement on a 10-year interval for relief valves. All LSSC testing is supplemented with performance monitoring and a requirement to maintain component reliability. Consistent with the intent of risk-informed initiatives, this represents a relaxation in testing requirements from the current OM Code.

The basis for this reduced level of testing and examination is the low safety-significance of the components. The process and requirements for categorizing components as low safety-significant verifies that plant safety is maintained even when a LSSC fails. The exercising and performance monitoring on LSSCs, and the requirement to maintain component reliability, continually assesses the performance of the LSSCs from a population and common-mode failure perspective and provides the owner confidence in operational readiness.

4.0 References

1. Requirements for Safety Significance Categorization of Components Using Risk Insights for Inservice Testing of LWR Power Plants, ASME OM Code Case OMN-1.
2. Alternative Rules for Preservice and Inservice Testing of Certain Electric Motor-Operated Valve Assemblies in Light-Water Reactor Plants OM Code-1995, Subsection ISTC, ASME OM Code Case OMN-1.
3. Check Valve Condition Monitoring Program, ASME OM Code Appendix II.

Session 2(b): Valves II

Session Chair

Steven M. Unikewicz

U.S. NRC

Effect of Butterfly Valve Disc Shape Variations on Torque Requirements for Power Plant Applications

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ABSTRACT

Tests sponsored by the U.S. Nuclear Regulatory Commission (NRC) at the Idaho National Engineering and Environmental Laboratory (INEEL) under the "Containment Purge and Vent Valve Test Program" in 1985 showed that manufacturers' methods for predicting torque requirements had serious limitations. Under design basis conditions, torque requirements in single-offset valves with shaft downstream were found to be self-opening, instead of self-closing as predicted by valve manufacturers. It was also found that variations in butterfly disc shapes are quite large and the influence of disc shape, upstream piping configuration, ΔP (differential pressure) and unchoked vs. choked flow conditions on torque requirements in compressible and incompressible flows had not been adequately addressed by the industry. The Electric Power Research Institute (EPRI), under its Motor-Operated Valve (MOV) Performance Prediction Program (1990-1994), developed analytical models and conducted tests to address some of these shortcomings. However, the models were based on simple analytical approaches with large conservatism to cover known uncertainties, and testing was limited to incompressible flow with only symmetrical and single-offset disc geometries. Furthermore, the EPRI methodology was developed for MOVs, which have a constant actuator output torque capability and, therefore, did require position dependent accuracy in torque predictions for margin evaluation. Torque prediction methodologies for Air-Operated Valves (AOVs) need to have position dependent accuracy because AOV actuator output varies with stroke. Consequently, the MOV methodologies are generally not suitable for accurate assessment of AOV margins.

This paper presents highlights of a comprehensive and advanced butterfly valve model development program that overcomes above limitations. Incompressible and compressible flow test programs have been described in earlier papers. The focus of this paper is to present the key results from analytical research and testing that overcome limitations that were identified in earlier programs. The disc shape and certain key geometric features that influence the valve performance are discussed. This paper also provides examples of the advanced models and the benefits derived from the efficient use of the massive database of flow and torque coefficients by software to address design basis evaluations for both incompressible and compressible flow plant applications

INTRODUCTION

To meet an important industry need for evaluating the capability of safety-related Air-Operated Valves (AOVs) to operate under design basis conditions, Kalsi Engineering, Inc., initiated a comprehensive program to develop validated models for quarter-turn valves. The program included development of first principle models, extensive computational fluid dynamics (CFD) analyses, and flow loop tests (incompressible and compressible flows) on all common types of AOV quarter-turn valves. The test program included systematic evaluation of a wide matrix of disc shapes, elbow orientations and proximities, and pressure drop ratios/flow rates on the required torque. The program was conducted under a quality assurance (QA) program that meets the Appendix B requirements in Part 50 to Title 10 of the *Code of Federal Regulations* (10CFR50). Earlier papers [1, 2]* provide and overview of the incompressible and compressible flow test programs. The products of this program are advanced, validated models and software (KVAP™) for AOV/MOV design basis sizing and margin calculations [13].

The new models and KVAP software have significantly advanced the state-of-the-art and provide the most comprehensive database in the industry for accurately predicting performance of all common types of quarter-turn and linear valves. This paper presents an overview of the previous industry developments relevant to this program, provides a discussion of key results/insights, and summarizes plant experience and the benefits achieved by the utilities from application of these new models at many nuclear power plants.

LIMITATIONS OF EARLIER BUTTERFLY VALVE PROGRAMS

NRC/INEL Containment Purge and Vent Valve Test Program

A survey performed by NRC/INEL [5] showed that valve manufacturers did not have validated methodologies for reliable torque predictions of butterfly valves that appropriately take into account the variations in disc geometry as a function of valve size, pressure class, and model; fluid media (compressible or incompressible); and pressure drop ratios and flow rates from fully choked to unchoked/low ΔP conditions. Many manufacturers had performed tests on a few small valves (usually 8" or smaller) and developed sizing predictions for their entire product line without considering the geometric deviations with valve size/pressure class and validating the predictions against large valve tests. Compressible flow tests were generally performed under low flow/low ΔP unchoked conditions across the valve; and the performance under choked flow conditions had not been properly addressed. The effect of different elbow configurations and their proximities on torque requirements had also not been evaluated by most manufacturers.

Under the "Containment Purge and Vent Valve Test Program," U.S. NRC/INEL performed tests on three butterfly valves (two 8" and one 24" valves from two manufacturers) with gaseous nitrogen under blowdown conditions [4, 5]. Testing was limited to single-offset disc design (Figure 1), because the NRC survey showed that this design had the dominant population in the U.S. nuclear power plants. The program included testing with upstream elbows at valve inlet with four different configurations.

One of the most surprising test results found by NRC/INEL was that under design basis conditions, the valve performance with shaft downstream orientation was totally opposite of manufacturers' predictions (self-opening throughout the stroke instead of self-closing over majority of the stroke).

The program did not include symmetric disc, double- and triple-offset disc designs, even though the population of double-offset disc designs in containment purge applications is relatively significant. Furthermore, tests on two valves in series (typical installation in containment purge applications) were not included. Most of the tests were performed under choked flow conditions, and only a few of tests under low ΔP, unchoked, flow conditions were performed. NRC/INEL provided recommendations to the industry for further testing to overcome these limitations.

EPRI MOV Performance Prediction Program (PPP)

EPRI MOV PPP was a comprehensive program to develop performance prediction models for gate, globe and butterfly valves. The program included incompressible flow testing on symmetric and single-offset disc designs of different aspect ratios [6, 7, 8]. The EPRI program objective was to develop a methodology for MOV applications. For MOV evaluations, only a *single value* for the *peak required torque* is needed, regardless of where the peak occurs (Figure 4A). Therefore, the analytical model development of the EPRI MOV Performance Prediction Methodology (PPM) did not require position-dependent accuracy in torque predictions. The analytical models that form the basis of EPRI MOV PPM symmetric and single-offset butterfly valve methodology were based on simplified, thin disc 2D (two dimensional) streamline analysis approximations. Adjustments to torque coefficients to take into account disc thickness (aspect ratio) and shape were based upon simple hydraulic resistance calculations, available industry data and engineering judgment. Relatively large margins had to be included in these approximate models to cover uncertainties, simplifying assumptions and the limitations of the then-available test data [6, 7].

Validation of the EPRI MOV PPM models against flow loop and in-situ test data showed that even though the *Required Torque* predictions bounded the EPRI test data [7, 8], the dynamic torque signature predictions lacked position dependent accuracy required for AOVs as shown in Figure 4B. The total required dynamic torque predictions as a function of disc position (also referred to as *Torque Signature Predictions)* were in some cases overly conservative, and in other cases nonconservative over large portions of the stroke, e.g., as shown in Figures 2 and 3. EPRI issued information notices, error notices and industry guidance to address potential known nonconservatism of EPRI MOV PPM predictions while evaluating AOVs [10, 11, 12].

Kalsi Engineering, Inc.'s Advanced Model

Development Program for AOVs/MOVs

To develop validated models with position-dependent accuracy for all common types of quarter-turn valves in nuclear power plants, and to overcome the limitations of the NRC/INEL "Containment Purge and Vent Program" and the EPRI MOV PPM discussed above, Kalsi Engineering conducted a comprehensive development program that included advanced analytical modeling, compressible and incompressible flow testing, The program spanned over three years and was conducted in two phases: Phase I focused on incompressible flow applications including analytical model development, flow loop testing, and validation. Under Phase II, advanced compressible flow models were developed based upon Computational Fluid Dynamics (CFD) analyses and compressible flow testing covering a wide range of pressure drop ratios from highly choked to unchoked conditions. The disc shape test matrix and highlights of the program results are presented below.

Matrix of Disc Shape Geometries

Surveys by NRC/INEL and EPRI Nuclear Maintenance Application Center (NMAC) show that the following basic butterfly valve disc types are commonly used in the industry:

- Symmetric Disc Butterfly
- Single-Offset Butterfly
- Double-Offset Butterfly
- Triple-Offset Butterfly

In addition to butterfly valves, Kalsi Engineering's recent survey from twenty nuclear plants showed that the following types of quarter-turn valves are also common in AOV applications:

- Spherical Ball
- Segmented (V-Notch) Ball
- Eccentric Plug
- Cylindrical/Tapered Plug

The advanced model development program performed by Kalsi Engineering covered both butterfly and other types of quarter-turn valves. Figures 5-9 show the geometry, relative proportions and key features for various types of butterfly valves that were tested. To adequately cover the variations in disc geometries common in nuclear power plant applications, a total of 25 disc shapes were included in the test matrix. In addition to systematically covering variations in the disc aspect ratio, the matrix also included scale models of disc geometries having exact geometrical similarities to the 18", 36", 42" and 48" valves used in safety-related nuclear plant applications. The scale model testing approach was used because this approach was validated against 42" full-scale valve test data under the EPRI MOV PPP.

The butterfly valve disc shape variations included in the test program are described below:

Basic disc types:	Symmetric & non-symmetric (single-offset, double-offset and triple-offset designs).
Disc aspect ratio:	0.15 to 0.31 for symmetric disc designs 0.09 to 0.47 for non-symmetric designs
Disc front face geometry:	Flat or recessed. The recess can be flat or concave (Figures 6, 7). The non-flat, recessed front face geometries are common in cast designs.
Disc shaft side geometry:	Prismatic, conical or radiused. This disc face can be relatively smooth (e.g., prismatic shapes typically fabricated from plate/machined components) or have bosses/projections and recesses (which are common in cast designs). Another variation in the shaft side disc faces included stub shaft hub design. Figures 6 and 7 show these geometric variations.

It should be noted that all tests on single-offset butterfly valves performed by NRC/INEL and EPRI MOV PPP used disc geometries, which had flat front faces as shown in Figure 1. The non-flat face geometries can have higher torque requirements than flat face geometries as will be discussed under Key Results.

Matrix of Incompressible & Compressible Flow Tests

Both incompressible and compressible flow tests were performed with baseline configuration (no upstream elbows within 20 pipe diameters) and with various elbow configurations and proximities (from 0 to 8D) as described in References 1 & 2. The test sequence for each valve installation/configuration typically consisted of 17 static/dynamic strokes for incompressible flow testing, and up to 24 strokes for compressible flow testing. This resulted in a total matrix of 1,272 tests for incompressible flow and 1,116 tests for compressible flow. The flow loop testing provided a massive database of nondimensional hydrodynamic torque/flow coefficients (for incompressible flow) and aerodynamic torque coefficients (for compressible flow) for various valve geometries over a range of wide flow conditions.

KVAP SOFTWARE*:* *The tool for efficient and user-friendly application of advanced models and massive database for complete AOV/MOV evaluations*.

The calculations necessary to predict torque requirements for quarter-turn valves are very extensive, time consuming and potentially error prone because they require a detailed knowledge of the methodologies, and a large number of parameters, which are application specific. This dictated the need for development of a software to help utility engineers perform calculations efficiently without being burdened with extensive interpolations required to account for:
(a) application specific torque/flow coefficients which depend upon valve geometry (disc shape, aspect ratio),
(b) installation parameters (disc orientation, elbow configuration/proximity), and (c) operating conditions (pressure, $\Delta P/P_{up}$ ratios, fluid media and flow rate). The advanced validated models as well as the massive database of torque and flow coefficients from the test program were incorporated into a PC based software called KVAP (Kalsi Valve and Actuator Program). The software was developed with emphasis on very intuitive and user-friendly graphical features. Table 1 provides a comparison of validated models that were developed under this program and incorporated in KVAP software against the previously available industry methodologies/software.

In addition to addressing quarter-turn valves, KVAP software includes all linear valves (gate, globe and diaphragm) as well as all commonly used AOV and MOV actuators. In summary, KVAP is designed to provide complete design basis evaluations and margins for all AOVs and MOVs in power plants [13].

QUALITY ASSURANCE

All testing, model development, and KVAP software development activities were conducted in accordance with our quality assurance program, which satisfies 10CFR50, Appendix B requirements.

DISCUSSION OF KEY RESULTS FROM ANALYSES & TESTING

Key Results From CFD Analyses
CFD analytical results (including pressure and velocity contours; shock wave location, strength and movement; and interaction between two valves in series) provided insights that were significant in understanding the behavior of butterfly valves in compressible flow. Figure 10 shows a comparison of the Mach number, pressure and velocity distribution for a symmetric disc butterfly valve operating under unchoked, relatively low $\Delta P/P_{up}$ conditions (left picture) against fully choked, high $\Delta P/P_{up}$ conditions (right picture). Under low $\Delta P/P_{up}$ operation, the flow becomes sonic just downstream of the leading edge, and it remains separated from the downstream disc face. However, under choked flow conditions, the flow shock front reattaches itself to the downstream disc face, as shown in Figure 10. The reattachment of the shock front to the disc downstream face causes a jump in the pressure distribution, which in turn dramatically affects the magnitude as well as the direction of the resultant aerodynamic torque on the disc. Furthermore, the reattached shock front changes its location on the downstream disc face as the $\Delta P/P_{up}$ ratio is changed. This explains the non-linear changes in aerodynamic torque as $\Delta P/P_{up}$ ratio is increased from low (nearly incompressible, unchoked conditions) to high (fully choked conditions).

The phenomenon described here is equally applicable to single- and double-offset disc designs with shaft downstream orientations, and it explains why the manufacturers' predictions (based upon unchoked, low ΔP tests) were contradictory to the NRC/INEL test under high ΔP, choked flow conditions. This is further discussed under "Key Results from Incompressible and Compressible Flow Testing" section in this paper.

The CFD analyses also showed that the presence of a downstream butterfly valve (Figure 11) can dramatically alter the pressure distribution and aerodynamic torque experienced by the upstream valve. This is due to the fact that the reduction in the flow area at the downstream valve location causes the flow to accelerate, which can cause the shock front to move from the upstream valve to the downstream valve location.

The significant insights obtained from the CFD analyses research provided excellent guidance for the key parameters to be varied in the test matrix for compressible flow testing. The test program covers a wide range of $\Delta P/P_{up}$ ratios from nearly incompressible, low ΔP conditions to highly choked flow conditions. The effect of various upstream and downstream resistances was also systematically evaluated to determine their effect on torque coefficients, as discussed in Reference 2.

Key Results from Incompressible and Compressible Flow Testing

Some of the key results for the incompressible and compressible flow testing that are discussed in this section are shown in Figures 12 to 15.

Validated Model for Double-Offset Disc Designs
Tests revealed that variations in hydrodynamic torque for double-offset valves (which were not included in the EPRI MOV PPP) can be significant based upon the combination of the first and second offset magnitude, as well as critical disc geometry features, e.g., a concave or recessed disc face instead of a flat face (Figure 12). The sensitivity of the torque coefficients and flow coefficients to streamlining the disc faces as shown in Figure 8 was also evaluated to provide bounding coefficients for the advanced models and KVAP software.

Aerodynamic Torque can Change From Self-Closing to Self-Opening with Changes in $\Delta P/P_{up}$ Ratio
Figure 13 shows that incompressible-flow torque coefficients are independent of pressure drop. Therefore, the hydrodynamic torque magnitude is linearly proportional to ΔP, and torque behavior at a given stroke position does not change (e.g., from self-closing to self-opening).

A comparison against the torque coefficients from compressible flow (Figure 14) shows that under low $\Delta P/P_{up}$ ratios, the behavior of the butterfly valve is basically the same as that under incompressible flow testing. Figure 14 also shows that aerodynamic torque for a single-offset disc, with shaft downstream, changes from *self-closing* (under low $\Delta P/P_{up}$, unchoked, nearly incompressible conditions) to *self-opening* as $\Delta P/P_{up}$ is increased to fully choked conditions. This is caused by the reattachment and movement of the shock front on the downstream disc face as discussed above under Key Results from CFD.

Geometry of Downstream Resistance can Provide Significant Relief in Aerodynamic Torque
Figure 15 shows that the geometry of the downstream resistance can have a profound effect on the torque requirements of butterfly valves. The comparison shows that the presence of a fully open downstream butterfly valve significantly lowers the aerodynamic torque of the upstream butterfly valve. An equivalent length of downstream pipe that has the same flow resistance as that of a fully open butterfly valve has a much smaller influence on the aerodynamic torque requirement of the upstream valve. Therefore, for appropriate application, a significant improvement in margin can be achieved by taking credit for this phenomenon. This is particularly important for containment purge valves that are installed in series (typically one valve inside and one valve outside the containment).

Advanced Models Account for Inaccuracies in Torque vs. Position Caused by Upstream Elbows
The presence of upstream flow disturbance (e.g., an elbow) near the inlet of butterfly valves (which is common practice in power plant applications) affects both the magnitude and distribution of the hydrodynamic torque, Thyd. A simple multiplier (like the one provided by the Upstream Elbow Model in EPRI's MPV PPM) cannot account for the shift in Thyd. Advanced modeling is necessary to maintain position dependent accuracy with the presence of upstream elbows.

For example, in a symmetric disc installation without upstream elbow, the hydrodynamic torque component at the fully open position is nearly zero because the flow around the disc is balanced. Upstream elbow installation near the valve inlet skews the flow velocity and pressure distribution around the disc even in the fully open position. This skew in flow velocity and pressure caused by the elbow results in a net positive or negative hydrodynamic torque in the fully open position. The magnitude and direction of the net Thyd depend on the relative orientation and proximity of the elbow with respect to the valve disc. The necessary development and validation for both compressible and incompressible flows have been incorporated in KVAP.

Recessed Faced Discs Exhibit Higher Torque than Flat Faced Discs

Testing with shaft downstream valve orientations showed that discs with recessed flat faces (Figure 7) exhibit higher Thyd than discs with true flat faces without a recess or a depression on the flat face (Figures 1 and 6) especially at the large disc opening angles. The increase in the magnitude of Thyd depends on the depth and extent of these flat face depressions. The advanced methodologies in KVAP account for the effects of typical depressions on torque requirements.

These tests results may show that earlier methodologies are not as conservative as they were considered prior to this test program. The reason is that flow loop testing (prior to KEI testing) was limited to discs with purely flat faces.

APPLICATION EXAMPLES, PLANT EXPERIENCE AND BENEFITS

Since the first release of the KVAP program in November of 2000, the software has been used for AOV and MOV evaluations at a large number of nuclear power plants. In many plants, substantial cost savings (often in excess of $500,000 at each plant) have been realized by the utilities by avoiding the need for modifications due to "apparent" negative margins predicted by other methodologies/software. The following examples show typical improvement in margins based upon the use of the more accurate models in KVAP for incompressible and compressible flow applications. In many instances, modifications of AOV groups containing multiple valves (up to eight in several cases) were proven unnecessary and successfully avoided. Such unnecessary modifications to increase the actuator output torque capability would also require re-evaluation of the AOV weak link and seismic re-qualification of the valve/actuator assembly.

Another significant cost benefit provided by the validated models incorporated in KVAP is that they provide an alternative to dynamic ΔP testing to evaluate the AOV/MOV capability to operate under design basis conditions.

Plant Example 1: Margin evaluation of AOV application highlights misconception. Figure 16 shows a typical input screen and the margin plot from KVAP analysis of an AOV from an actual plant evaluation of a symmetric disc butterfly valve with a Scotch Yoke actuator used in an incompressible flow application. In this application, the minimum AOV margin is dictated by the dynamic torque at around the 25-degree location and not by the unseating torque (at closed position), which is significantly higher. The unseating torque would govern the margin for an MOV where actuator output is constant throughout the stroke. This example shows the importance of position-dependent accuracy in torque prediction models.

An important *general* observation from this plant example is that even though seating/unseating torque may be the highest torque throughout the stroke, this may not dictate the minimum margin in an AOV (unlike in an MOV).

Plant Example 2: Identification of "apparent" negative margin eliminates need for unnecessary modifications. This plant had performed design basis calculations for the six service water butterfly valves operated by piston actuators with lever-and-link mechanism for quarter-turn operation. These AOVs had a maximum disc-opening angle of 60°. Based upon earlier industry methodologies, it was concluded that this AOV had a negative margin under design basis calculations (Figure 17). Modifications were planned to change the actuators to provide higher torque outputs to meet the requirements indicated by the previous analysis. Re-evaluation (using the more accurate validated models described in this paper) showed a positive margin was actually available throughout the stroke. This eliminated the need for changing actuators, resulting in significant cost savings without compromising safety/reliability of valve operation.

Plant Example 3: KVAP application improves margin in containment purge application. Figure 18 shows the comparison of required torque predictions for an 18" double-offset disc containment purge valve (with shaft downstream orientation) to close under design basis Loss of Coolant Accident (LOCA) conditions. The AOV actuator was a Scotch-Yoke type with spring return to fail close the valve. The minimum actuator output available from the actuator at various stroke positions had been provided by the manufacturer and verified by the plant engineers. EPRI MOV PPM software indicated a large negative margin throughout the stroke. The use of KVAP software, along with the use of torque/flow coefficients database based upon the appropriate $\Delta P/P_{up}$ ratio for this application, resulted in a significant reduction in torque requirements, and a positive margin throughout the stroke. This eliminated the need for plant modifications that were being planned for 8 valves in this group of Category 1 AOVs.

CONCLUSION

The advanced, validated models and KVAP software successfully fulfill the industry need for reliable position-dependent torque predictions for AOVs. The benefits in margin improvement from KVAP are also applicable to MOV applications. Validated models provide an alternative to ΔP testing. Plant experience has shown significant cost savings by avoiding equipment modifications in many applications. KVAP margin improvements may be used to ease plant equipment modification and maintenance burdens by enlarging AOV and MOV actuator field set-up windows, extend periodic verification inspection and test intervals, and improve power uprate and life extension decisions. KVAP software is an efficient, intuitive, and user friendly software developed under our 10CFR50 Appendix B QA program to provide reliable predictions for safety-related applications.

ACKNOWLEDGEMENTS

Kalsi Engineering and the authors acknowledge contributions made by the valve manufacturers, NRC/INEL, EPRI/NMAC, and power plant engineers over the years which led to improved understanding and development of advanced models described in this paper.

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	Valve Types Prevalent in AOV Population	NRC/INEL Cont. Purge	EPRI MOV PPM (Note 1)	Ace, AirBase, Others (Note 2)	KVAP Software
1	Symmetric Butterfly	None	√*	None	√
2	Single-Offset Butterfly	√**	√	None	√
3	Double-Offset Butterfly	None	None	None	√
4	Segmented V-Ball	None	None	None	√
5	Spherical Ball	None	None	None	√
6	Eccentric Plug	None	None	None	√
7	Tapered/Cylinder Plug	None	None	None	√

*** Incompressible Flow Only**
**** Compressible Flow Only**

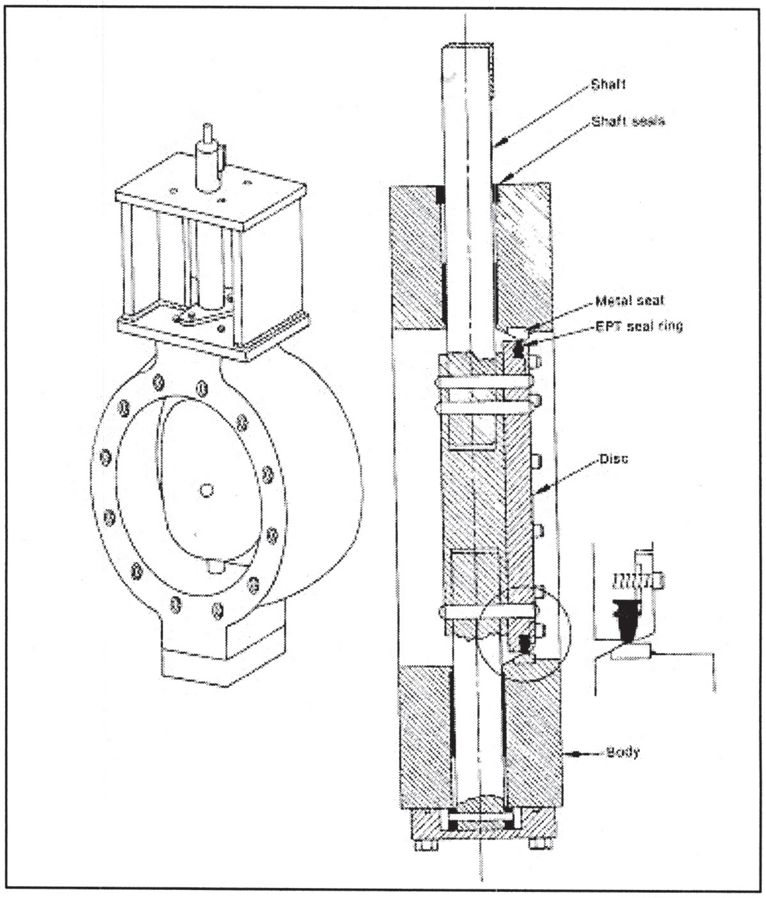
General Note: NRC/INEL and EPRI MOV PPP methodologies for single-offset discs were based upon tests performed on discs having flat front faces (no recesses) that may not bound data for recessed designs. Recessed faces are common in cast disc designs.

Note 1: EPRI MOV PPM models provide bounding predictions for MOVs. EPRI Torque Signature predictions can be nonconservative over portions of the stroke. See EPRI MOV PPP Software Information and Error Notices [10, 11, 12].

Note 2: ACE, AirBase, and other software, e.g., Excel spreadsheet, do not have built-in validated torque/ flow coefficients. Predictions based on the use of EPRI MOV PPM coefficients in these softwares can be nonconservative over portions of the stroke. See EPRI MOV PPP Software Information and Error Notices [10, 11, 12].

Table 1

Comparison of Validated Methodologies Available in KVAP Against Other Methodologies/Software



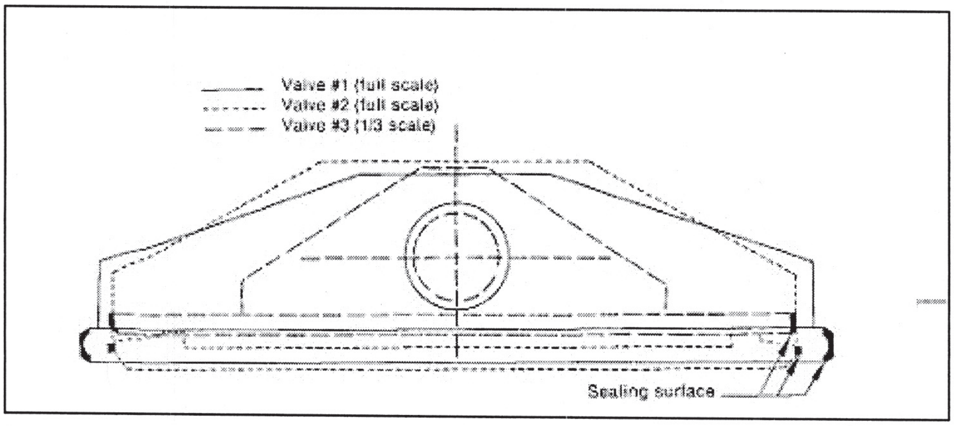


Figure 1: Details of a single-offset butterfly valve (top) and a composite drawing (bottom) showing geometric comparison of disc cross-sections of 3 different disc shapes from 2 manufacturers tested by NRC/INEL [4, 5].

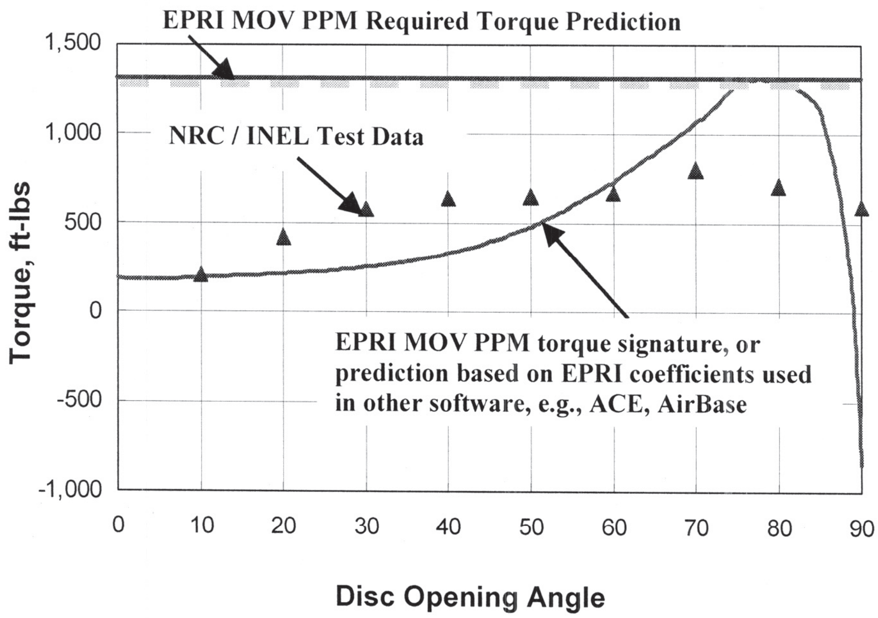
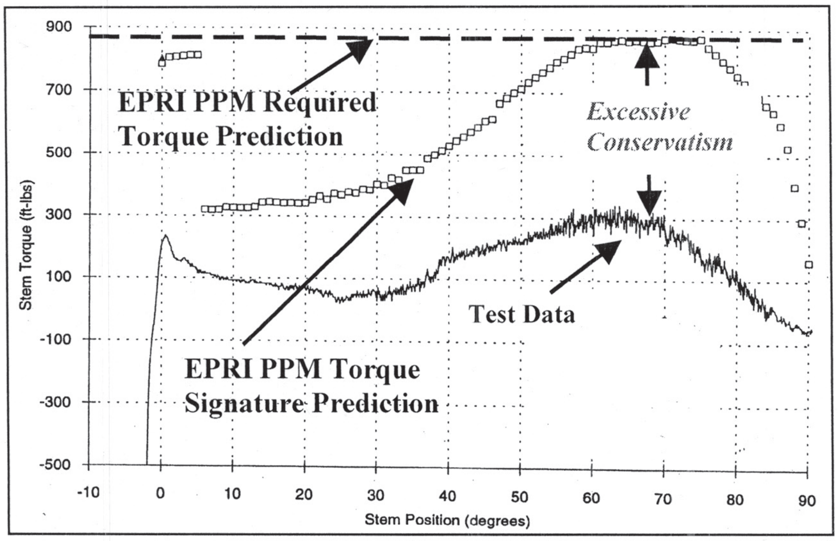
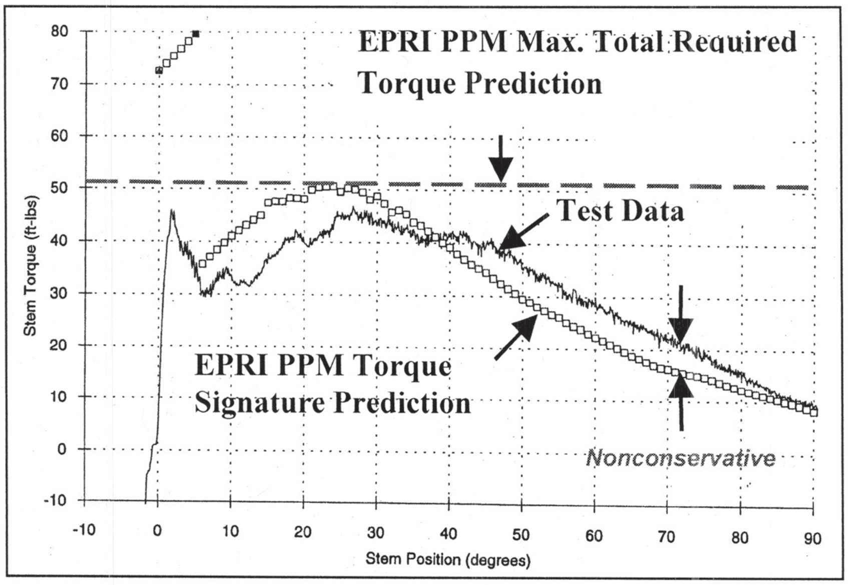


Figure 2: EPRI MOV PPM Required Torque bounds NRC/INEL compressible flow test data, but Dynamic Torque predictions (also called Torque Signature predictions) are nonconservative over a large portion of the stroke.



EPRI Valve Test No. F-55



EPRI Valve Test No. I-27

Figure 3: The Total Dynamic Torque predictions (Torque Signature) from EPRI MOV PPM for incompressible flow applications can be overly conservative (e.g., top figure) or nonconservative (e.g., bottom figure) depending upon valve type and application.

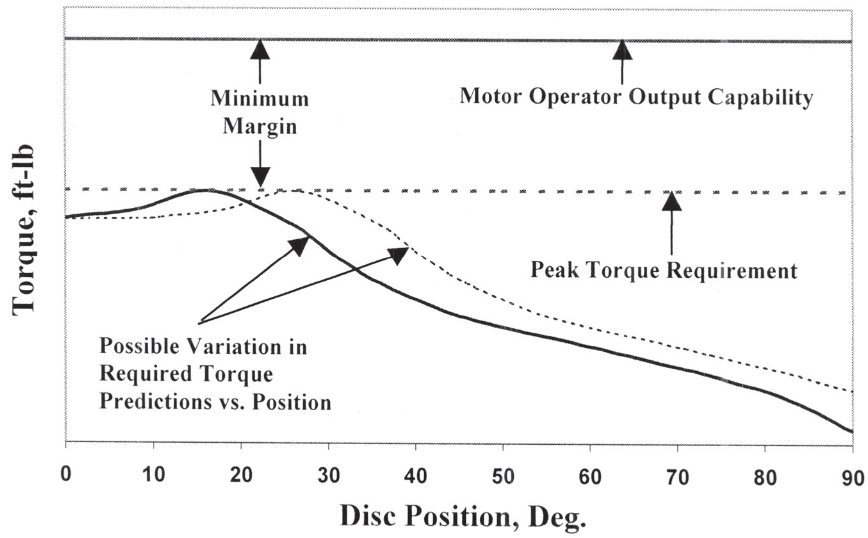


Figure 4A: Typical MOV actuator output is constant throughout the stroke; only peak torque magnitude (regardless of stroke position) dictates the minimum margin.

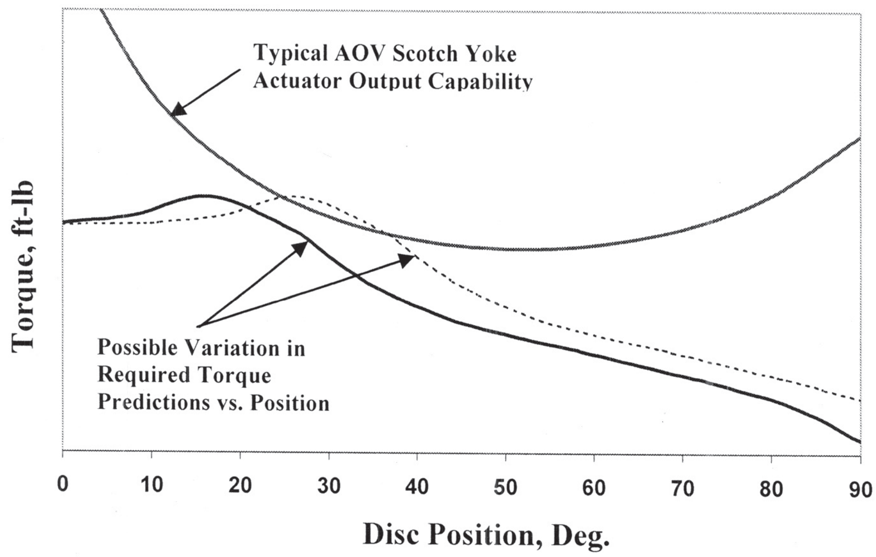


Figure 4B: Typical AOV actuator output varies with position; valve torque requirements must be accurately determined at each stroke position to calculate minimum margin throughout the stroke.

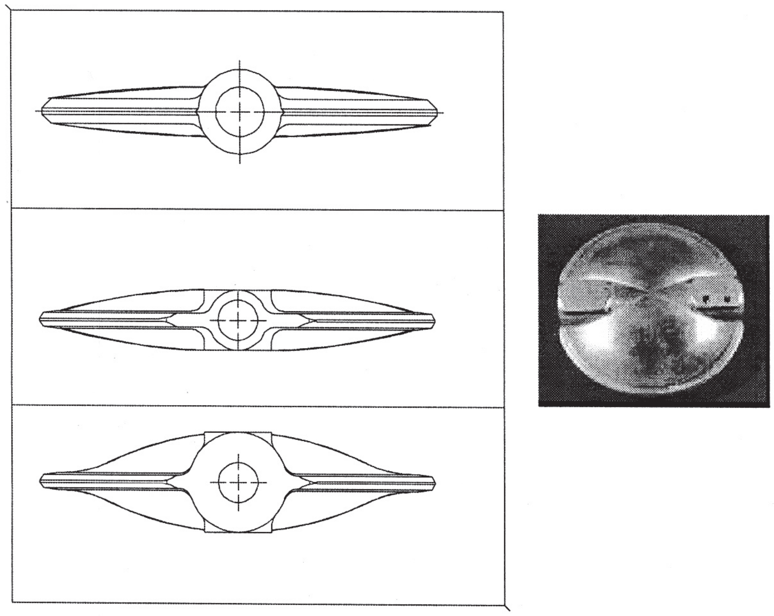


Figure 5: Symmetric discs with different aspect ratios.

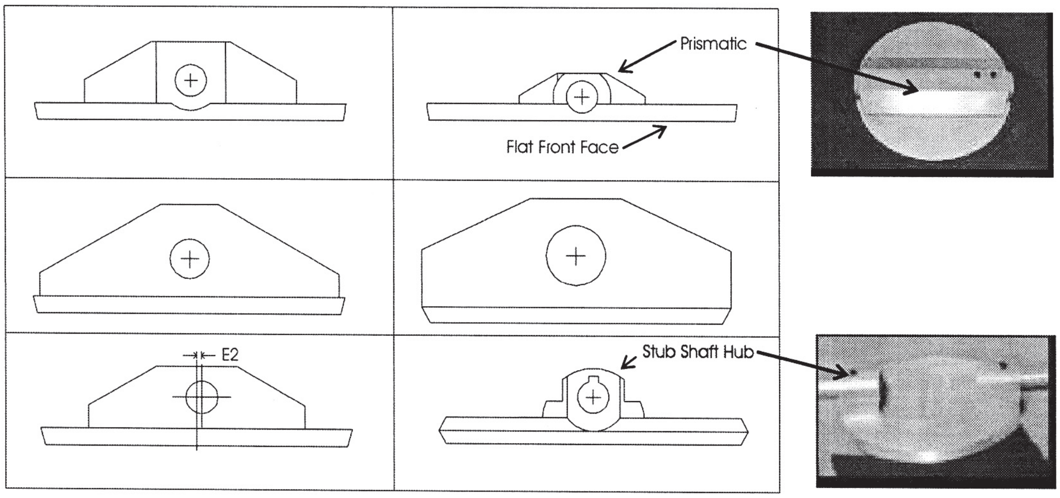


Figure 6: Flat front faced single- and double-offset discs of various aspect ratios and geometries.

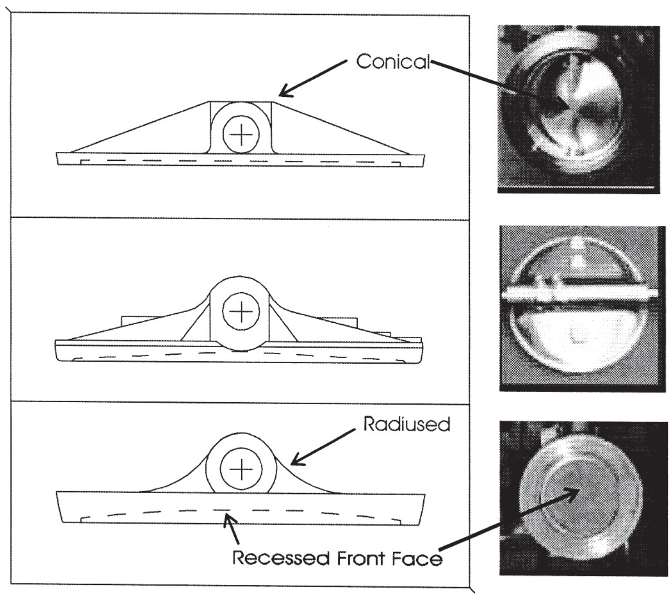
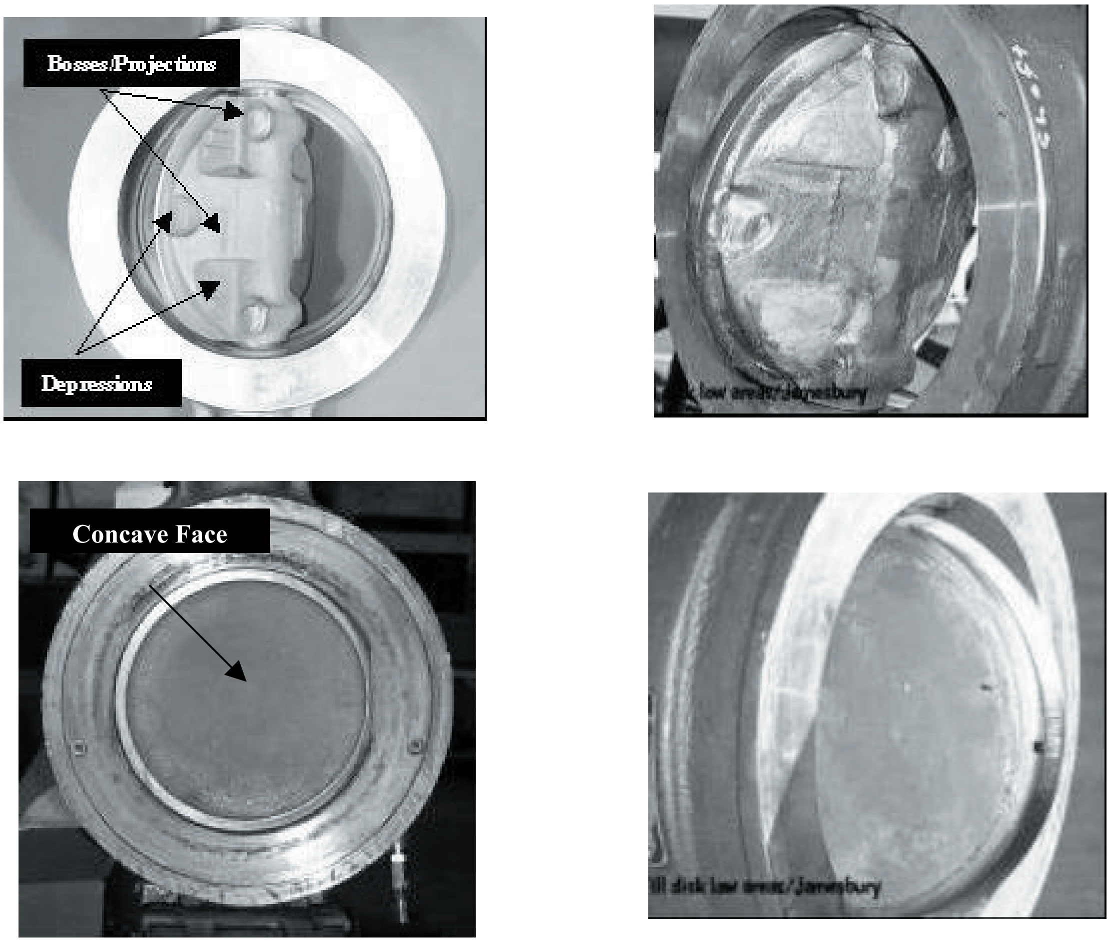


Figure 7: Recessed front faced single- and double-offset disc geometries.



Original Disc from Manufacturer **Disc Faces Streamlined with Filler**

Figure 8: Test matrix included sensitivity evaluation of streamlining both the upstream and downstream disc faces on hydrodynamic torque.

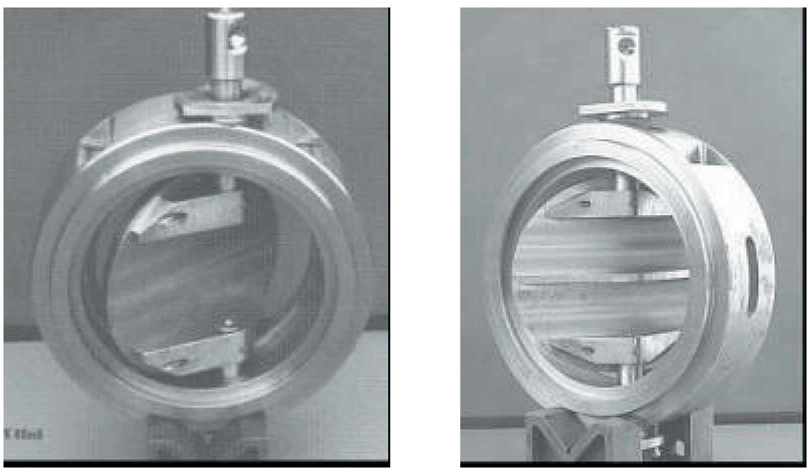


Figure 9: Triple-offset discs with large second offset were included in the test matrix.

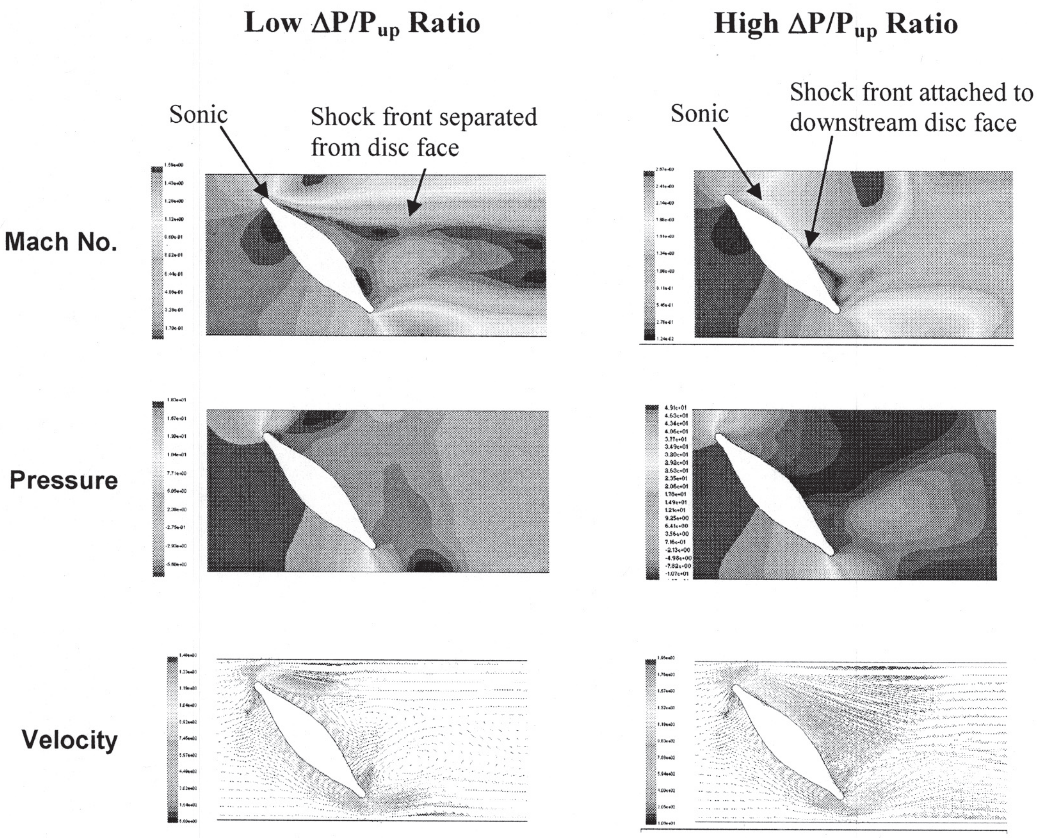


Figure 10: Compressible flow CFD analyses under low and high DP/Pup conditions show that shock front reattachment/location on the downstream disc face causes significant changes in pressure distributions, which dictate aerodynamic torque.

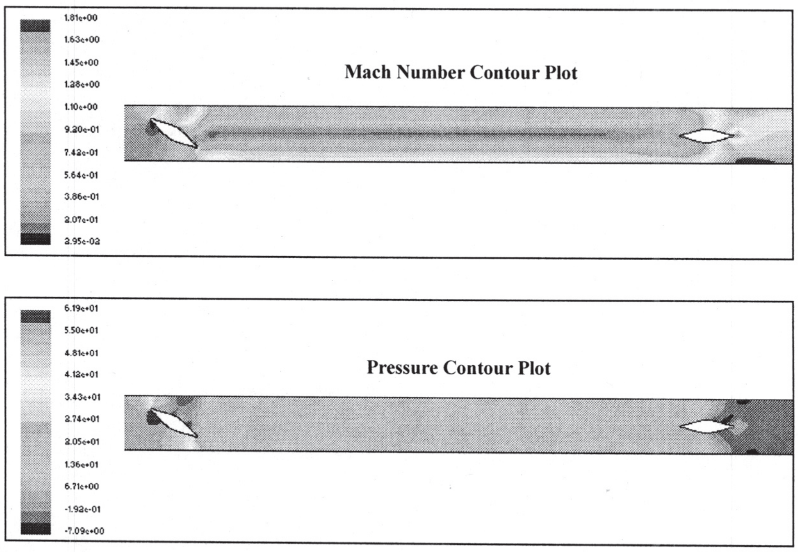


Figure 11: The presence of a downstream valve significantly alters the DP/Pup ratio across the upstream valve by causing changes in pressure distribution on its downstream disc face, which dictates the aerodynamic torque.

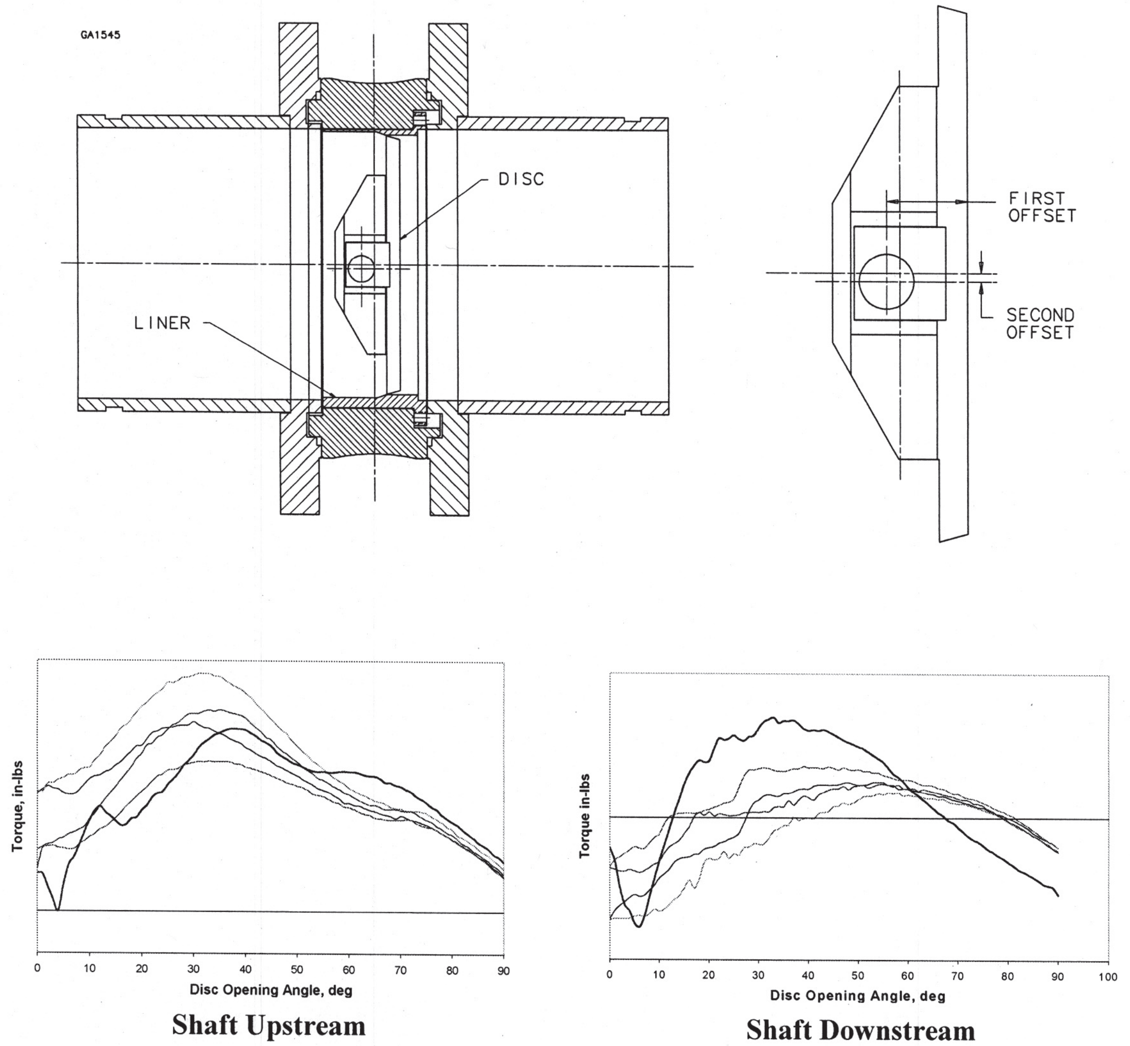


Figure 12: Combinations of the first and second offset magnitudes were systematically varied to evaluate their effect on the hydrodynamic torque for double-offset disc valves.

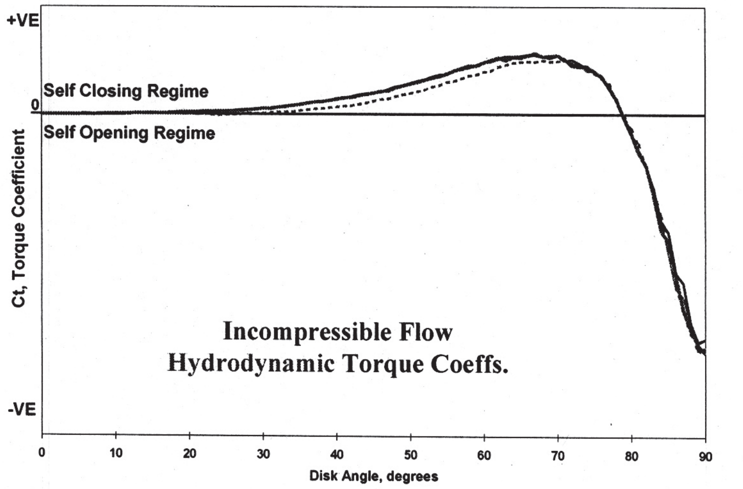


Figure 13: For incompressible flow, torque coefficients are independent of pressure drop, therefore torque magnitude is proportional to DP, and torque behavior remains the same between low and high DP conditions.

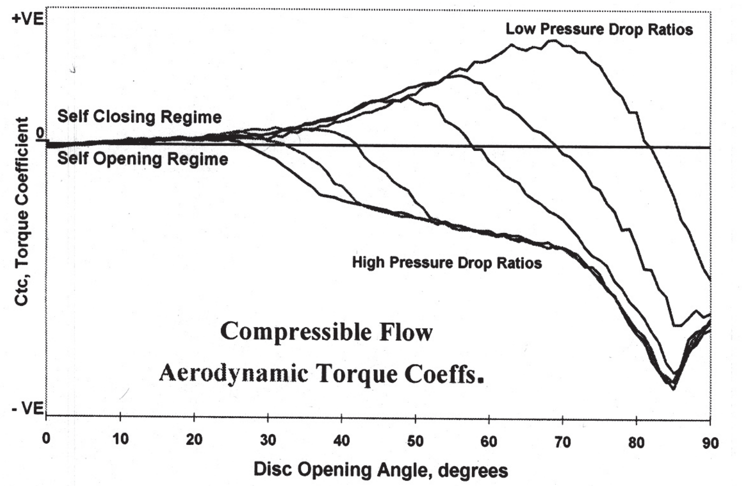


Figure 14: For compressible flow, torque coefficients change from self–closing regime to self-opening regime as the DP/Pup ratio is increased.

Note: *This explains why NRC/INEL [4,5] tests under containment purge conditions (high DP/Pup ratios) exhibited self-opening torque whereas manufacturers predicted self-closing torque (based upon their low DP/Pup ratio tests).*

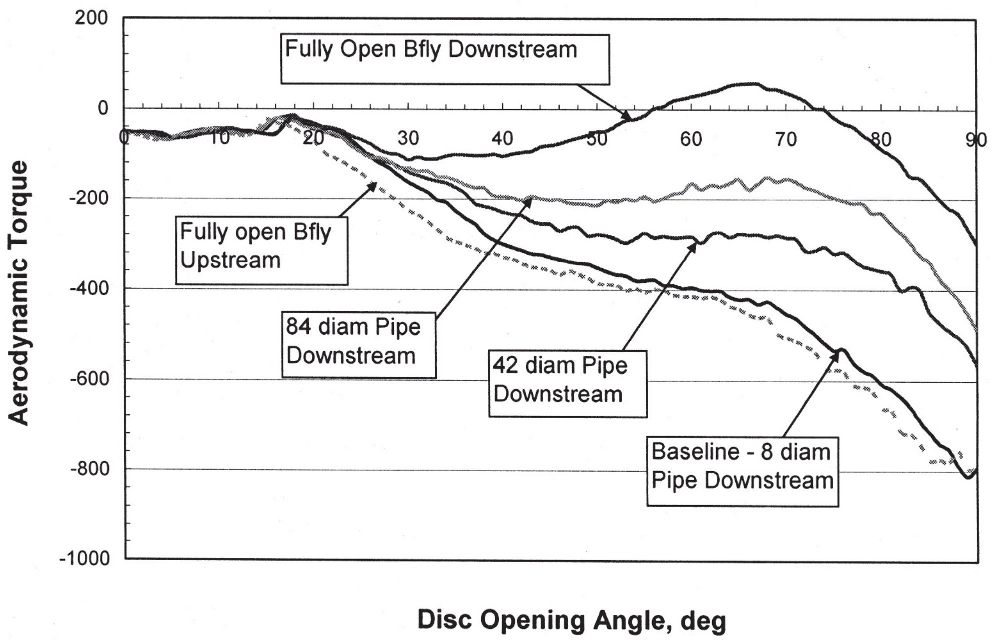


Figure 15: Geometry of downstream flow resistance (e.g., a butterfly valve instead of an equivalent length of pipe) has a profound effect on the aerodynamic torque.

Note: *In this comparison, a fully open downstream butterfly valve significantly lowers aerodynamic torque on upstream butterfly valve, as compared to an equivalent resistance length of downstream pipe (42 diam.). This can increase margin, eliminate unnecessary modifications and allow operation under plant modes previously not permitted.*

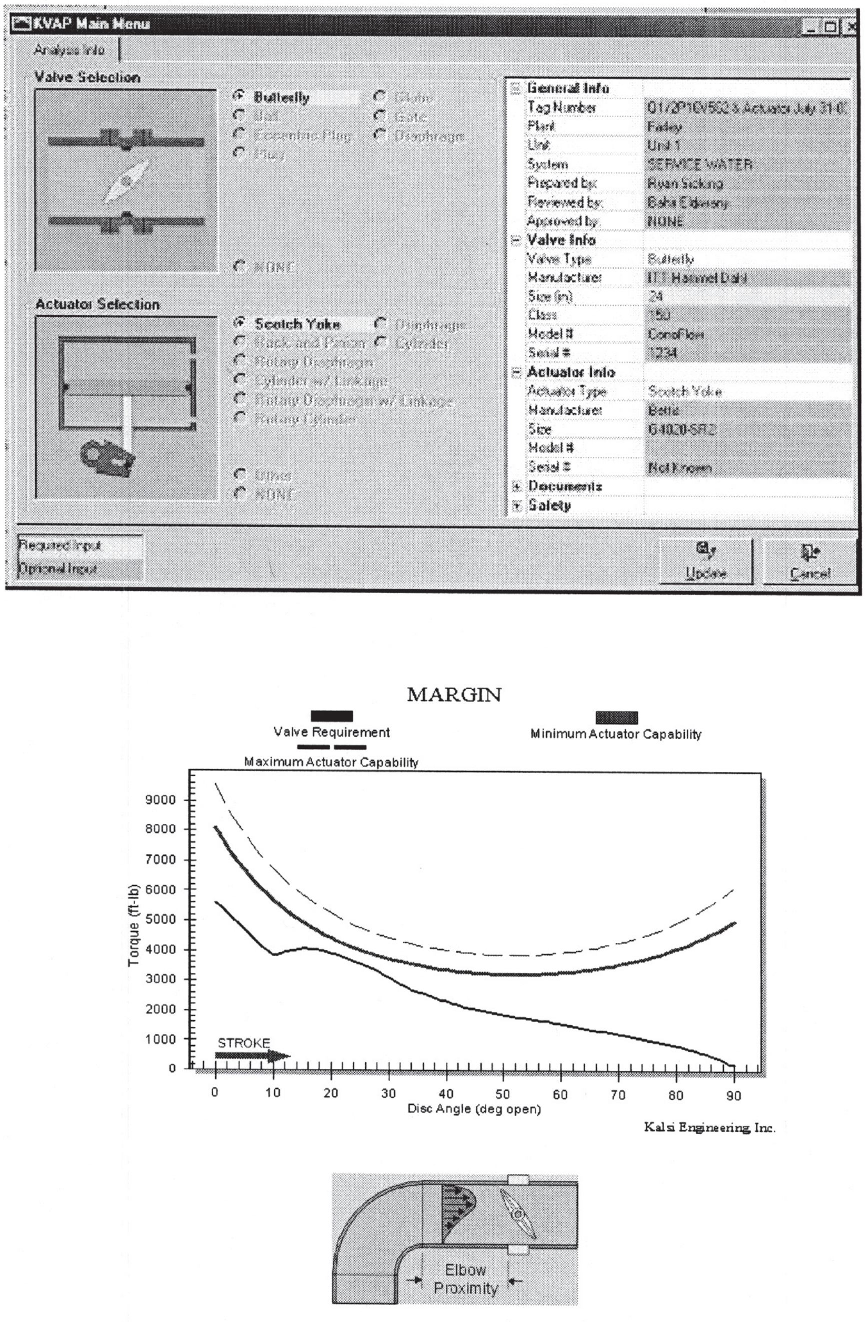


Figure 16: Graphically oriented and intuitive user-friendly features of KVAP for input and output screens eliminate the potential for error, and permit efficient calculations by interpolating flow and torque coefficients from the extensive built-in database for the application-specific attributes (e.g., disc geometry, aspect ratio, DP/Pup ratio, upstream elbow configuration and proximity).

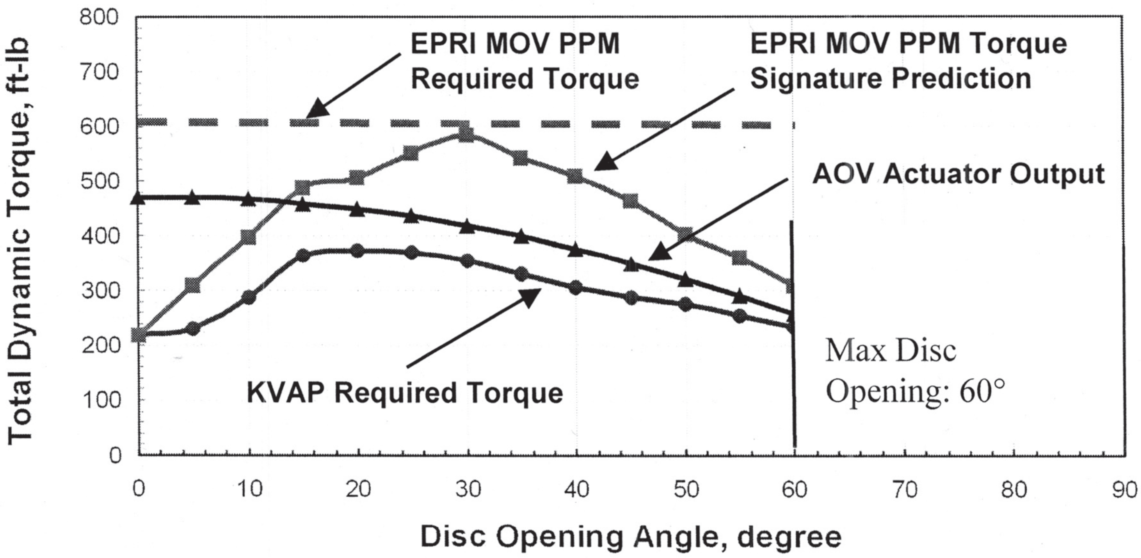


Figure 17: KVAP Margin improvements for 16" butterfly valves in a service water application eliminated the need for modifications indicated by EPRI MOV PPM.

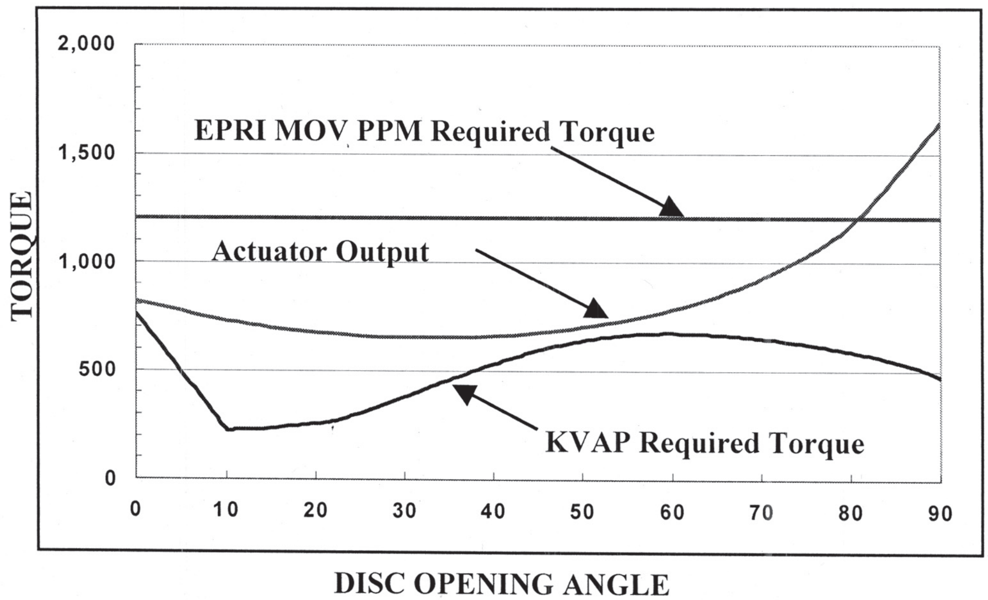


Figure 18: KVAP Margin improvement achieved for 18" butterfly valves in containment isolation application eliminated the need for modifications indicated by EPRI MOV PPM.

Actuator Capability and Rating Evaluation for Non-Limitorque Actuators in Korea NPPs

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Abstract

The safety assessment for MOVs (motor-operated valves) in Korea NPPs (nuclear power plants) has been performed to implement US NRC Generic Letter 89-10 (GL 89-10: Safety-Related Motor-Operated Valve Testing and Surveillance). This safety assessment consisted of a design basis review and a diagnostic test. Since the information on non-Limitorque actuators is not enough, a TTS (torque test stand) has been introduced in the safety assessment program to support the actuator capability evaluation of non-Limitorque actuators. In order to evaluate the TTS test results, a direct and indirect method as an engineering scheme and eTTS program as a software tool have been developed. The results indicate that the real actuator output torques for Joucomatic actuator models (80L111, 80L20, DR10.35, DR10.58, DR40.72, and DR5.58) are 20%~100% greater than those of design basis review. For the EIM-30 model, the real actuator torques are very close to the design basis actuator torque.

In addition, the actuator rating analyses are performed for Joucomatic actuators because the actuator ratings for the actuators are not found from documents. For Limitorque actuators, the three consistent failure points are the worm tooth at the worm/worm gear contact, the worm shaft at the worm/worm shaft contact point, and the root of the limit switch worm. However, the only failure point is the worm tooth at the worm/worm gear contact for Joucomatic actuators. The actuator ratings calculated are highly conservative but useful for implementing GL 89-10.

1. Introduction

The safety assessment for MOVs (motor-operated valves) in Korea NPPs (nuclear power plants) has been performed to implement the US NRC GL 89-10. This safety assessment mainly consists of a design basis review and a diagnostic test. The design basis review includes a system analysis, a required stem torque/thrust analysis, a weak-link analysis, a voltage degradation analysis, an actuator capability analysis, and margin analysis. The diagnostic tests are divided into a static test and a dynamic test.

The population of safety class actuators in Korea NPPs is shown in Table 1. Limitorque is a major contributor providing 73.4% of total safety class actuators, followed by Rotork (15.3%), and Joucomatic (6.8%). It was noticed that Joucomatic, Hopkinsons and EIM actuators are only found in Ulchin 1&2, Kori 1&2 and Wolsong 1, respectively.

Limitorque and Rotork provide sufficient information to assess an actuator capability relatively whereas other vendors do not provide an actuator efficiency, a rated torque, etc, which makes actuator capability calculations difficult. Therefore, the TTS (torque test stand) has been introduced in the safety assessment program to support the actuator capability evaluation of non-Limitorque actuators. The TTS consists of a power cabinet, a control panel and sensor, and a main body which has a pneumatic break system, a hydraulic thrust system, an adapter and a sleeve connector, and dynamometer. In order to evaluate the TTS test results, a direct/indirect method as an engineering scheme and eTTS program as an analyzing software tool have been developed. This paper describes test experience for the non-Limitorque actuators in Korea NPPs with the aid of TTS equipment.

In addition, the actuator rating analyses are performed for Joucomatic actuators because the actuator ratings for the actuators are also not found from documents. For Limitorque actuators, it is the worm and worm shaft that are known to have the greatest probability of failure during operation. The three consistent failure points are the worm tooth at the worm/worm gear contact, the worm shaft at the worm/worm shaft contact point, and the root of the limit switch worm for Limitorque actuators. However, the only failure point is the worm tooth at the worm/worm gear contact for Joucomatic actuators. Minor's rule was used to obtain the fatigue stress for the worm tooth. The material S-N curves are given by the "Criteria of the ASME Boiler and Pressure Vessel Code" including American Society of Mechanical Engineers (ASME) material properties. The actuator ratings calculated are highly conservative but useful for implementing GL 89-10.

2. Actuator Capability Evaluation

Design Basis Review of Actuator Capability

The actuator capability can be typically obtained by analyzing voltage drop, actuator efficiency, environmental temperature, etc. For an AC motor and a DC motor, the motor starting torque at a reduced voltage condition is proportional to the square of the voltage, whereas it varies proportionally with change in available voltage for a DC motor. The motor starting torque at reduced voltage condition can be obtained as follows:

$$MT_{DV} = MST \times DVF \tag{1}$$

$$DVF = (VT/VR)^{N} \tag{2}$$

where

MST = motor starting torque

DVF = degraded voltage factor

VT = motor terminal voltage

VR = motor rated voltage

N = 2 for AC motor and 1 for DC motor

The actuator torque also varies proportionally with motor starting torque, motor input voltage, actuator efficiency, overall gear ratio and environmental temperature condition. The actuator torque is generally given as follows:

$$TQ_{DV} = MT_{DV} \times OVR \times PULL_{eff} \times AF \times TDF \tag{3}$$

for gate and globe valves and

$$TQ_{DV} = MT_{DV} \times OVR \times PULL_{eff} \times AF \times TDF \times QGR \times QGR_{eff} \tag{4}$$

for butterfly valves,

where

TQ_{DV} = actuator output torque under degraded voltage condition

OVR = overall gear ratio

$PULL_{eff}$ = pull-out efficiency

AF = application factor

TDF = temperature degradation factor

QGR = quarter turn gear ratio

QGR_{eff} = quarter turn gear efficiency.

TTS and eTTS Program

The real actuator capability was measured with the aid of the TTS. The TTS, shown in Figure 1, was designed and engineered by Kalsi Engineering, Incorporated (KEI). It is designed to provide a torque resistance ranging from 12.5 foot-pound force (ft-lbf) to 3,600 ft-lbf. This is less than the 20 ft-lbf rated torque of the smallest Rotork 7A actuator up to the stall torque of the Rotork 90 series actuator. It consists of a power cabinet, a control panel and sensor, and a main body. The main body has a pneumatic break system, a hydraulic thrust system, an adapter and a sleeve connector, and a dynamometer. Also, it is equipped with a manually operated hydraulic system, which provides up to 75,000 lbf of upward or downward thrust load on the actuator. This simulates the stem thrust of the valve, and provides a realistic load on the thrust bearings of the actuator.

Since the raw signal from the TTS includes a lot of noise, the eTTS program was developed by KOPEC and Monitoring and Diagnosis (M&D) to remove the noise and manage test signals effectively. The eTTS program in Fig.2 consists of a filter module, an analysis module that extracts the voltage drop ratio and the actuator efficiency, a database module, and a complete graphic module. The raw signal was generally filtered by RTA (run time averaging) method, which is incorporated in the eTTS program.

Actuator Capability Evaluation through TTS Test

The actuator capability was analyzed with a direct method and an indirect method. A brief description for both methods is given below.

Direct Method. The actuator torque is directly taken from the TTS test. This method is generally applied to the valves with negative margin to obtain real actuator capability. Because it is difficult to evaluate the temperature degradation factor and set a test voltage for an exact design voltage with the TTS, some engineering process is required. After testing several times at a specified voltage condition, a voltage drop ratio is extracted. The actuator capability is then recalculated through Eqs. (1)~(4). The direct method was applied to EIM actuators.

Indirect Method. This method is similar to a grouping concept to evaluate the valve factor. The capability of the same group of actuators was assessed from testing actuator specimens that are easily taken in the plant or the same spare actuators. In addition, the Joucomatic actuator capability was calculated through an interpolation or extrapolation on the certified torque, which is provided by the vendor. The indirect method for Joucomatic actuator was accomplished by comparing the test result with the certified torque.

The Autotork actuator capability was verified by a statistical method as follows (one of the indirect method). For several test voltages, the 2nd order curve fitting of actuator torque is obtained by the least square method as follows:

$$Tq = aVR^2 + bVR + c \tag{5}$$

where a, b and c are the coefficients of the curve fitting equation. The actuator torque at each testing voltage, Tq_i, is recalculated with Eq. (5), which is $Tq_{cal,i}$. The deviation of actuator torque is easily obtained by:

$$\sigma_{Tq} = [\sum_{i=1}^{N} [Tq_i - Tq_{cal,i}]/(N-2)]^2 \tag{6}$$

where N represents the number of tests at each test voltage. The presumed actuator torque at the design basis voltage condition, Tq_{DB}, is then calculated with Eq. (5). Finally, the applied actuator torque at the design basis voltage condition, $Tq_{DB,a}$, is calculated as follows:

$$Tq_{DB,a} = (Tq_{DB} - t_{95} \times \sigma_{Tq}) \times TDF / U_{eff} \tag{7}$$

where U_{eff} and t_{95} represent an uncertainty and a statistical distribution according to testing, respectively.

TTS Test Results

TTS tests had been carried out for non-Limitorque actuators to obtain an appropriate actuator capability. Table 2 shows the matrix of test actuators. The matrix includes several actuator models from different actuator vendors. The method in Table 2 means the evaluation methodology of TTS test results as mentioned above. Most of the Joucomatic actuators were spares, whereas others are operating ones.

The results of design basis review for the non-Limitorque actuators are shown in Table 3. The design basis review was conducted through Eq. (1) ~Eq. (4) by assuming the actuator efficiency and the temperature degradation factor from the Limitorque test information. It is seen that, as the voltage condition goes higher, the actuator output becomes stronger in Table 3.

The actuator output torque from the TTS test is shown in Table 4. For Joucomatic models (80L111, 80L20, DR10.35, DR10.58, DR40.72, and DR5.58), the real actuator output capability is 20%~100% greater than those of the design basis review. Therefore, it can be estimated that the actuator capability from the design basis review for Joucomatic was very conservative. For Autotork NQ-60 model, the real actuator output was less than that of the design basis review. Because the Autotork NQ60 model was the smallest one in the test models and the actuator output torque was at the bottom sensitivity limit of the TTS equipment, it is difficult to obtain an accurate result. Since the Autotork NQ60 has sufficient margin, the test was terminated after obtaining an acceptable actuator torque. Also, for EIM-30 model, the real actuator torques are very close to the design basis actuator torque.

3. Actuator Rating Evaluation

The actuator rating analyses were performed for Joucomatic actuators because actuator ratings for the actuators are not provided from the vendor. The general configurations of DR and L types Joucomatic actuators are shown in Figure 3 in a cutaway view showing the major mechanical components of the system. The vertical translational motion of the actuator valve stem is generated by the worm/worm gear set. The worm machined on the worm shaft is directly driven by an electric motor for the DR type actuator. However, for the L type actuator, the worm, which is also machined on the worm shaft, is driven by an electric motor through a helical gear set. The worm in turn drives the worm gear that is directly coupled to a stem nut. The stem nut rotation creates the linear motion of the valve stem.

For Limitorque actuators, it is known that the worm and worm shaft have the greatest possibility of failure during operation. The three consistent failure points are the worm tooth at the worm/worm gear contact, the worm shaft at the worm/worm shaft contact point, and the root of the limit switch worm for Limitorque actuators [6]. However, the only failure point is the worm tooth at the worm/worm gear contact for Joucomatic actuators because the limit switch worm is not on the driving shaft and there is no worm/worm shaft contact point.

Analysis Method

The cumulative damage integral (CDI) for a ramp is given by Kalsi as:

$$\mathrm{CDI} = \int_{S_e}^{S_{ao}} \frac{\left(\dfrac{N_o}{S_{ao}}\right) dS_a}{\dfrac{1}{(9.25EC_f)^{1/b}} \left\{ \dfrac{S_a}{\left[1-(S_{mo}/S_u)^y\right]^{1/x}} - B \right\}^{1/b}} \tag{8}$$

where

$$C_f = \ln\left(\frac{1}{1-A}\right)$$

$$A = F_A RA$$

$$b = -F_b RA$$

$$B = F_B S_e$$

$$S_f = S_u + 50{,}000\,psi$$

and where S_{ao} is the maximum stress reached in the ramp, N_o is the total number of shaft revolutions in the load ramp, S_e is the endurance of the worm material, E is the modulus of the elasticity, RA is the fractional reduction of area, S_a is the alternating stress, S_{mo} is the maximum mean stress reached in the ramp, S_u is the ultimate tensile strength of the material, and x and y are the exponents to represent mean stress effects on fatigue. F_A, F_B and F_b are the empirical factors to facilitate a better correlation with the equation of S-N curves. We did not use the empirical factors because we had not performed the testing for the actuator. Therefore, we used $F_A = 1$, $F_B = 1$ and $F_b = 0.5$. And we use the Modified Goodman criteria for accounting of mean stress effects on fatigue life, that is, x = 1 and y = 1.

The most important factors affecting the operating life of the actuators are the load profile of the applied torque, and the gear ratios of the actuator torsional components. The typical load curve for a Joucomatic actuator valve under static condition is shown in Figure 4. The wedging and unwedging load ramps are linear and have very short durations. These steep ramps require relatively few revolutions from the worm to perform the actuation resulting in fewer stress cycles that contribute to fatigue damage. However, it is known that the road ramps under dynamic conditions are of longer duration with only a piece-wise linear profile. Therefore, a higher number of worm revolutions are required for actuation in comparison to the static condition; and the magnitude of closing torque is much larger than that of the opening torque. The actual damage depends on load magnitude and the required number of worm revolutions. We have used static test data with the maximum static stress and 1.5 times the duration of operating time for conservatism.

The analysis model used for the worm shaft configuration for the DR type actuators is shown in Figure 5. For the L type actuators, helical driving gear set is included to the DR type actuator model. The dimensional data for the calculation are obtained from drawings and by direct measurement. The worm shaft is directly connected to a motor for DR type actuators. The model shows forces and dimensions for the worm shaft. The external forces applied on the worm are designated F_w, and on the driving gear are designated F_d. The bearing reaction forces are designated B_1 and B_2 for the shaft.

The external forces and the bearing reaction forces resulting from the valve stem torque and thrust are calculated for both loading and unloading conditions. The worm stresses and the worm body stresses are also calculated. Mean and alternating von Mises stresses are computed for the critical location and are applied to the equation (8). The theoretical stress concentration factors, such as stress concentration factor, size effect, surface finish factor, and fatigue notch factor, are applied to the only alternating von Mises stress.

The thrust rating analysis was not performed. It is addressed in the weak link analysis in part, and the actuator bearing thrust was compared with the maximum thrust.

Rating Analysis Results

The results of the rating analysis of Joucomatic actuators are shown on Table 5. The certified torques and the performance margins shown on Table 1 are the capability of the actuators at 15% under-voltage and at 0 voltage drop from the vendor maintenance manual [7]. The actuator types 80L 111 and 80L 20 have the same configuration and dimension except worm tooth profile. Therefore, the calculated ratings are nearly same. The actuator types DR 5 and DR 10 and the actuator types DR 20 and DR 40 also have the same configuration and dimension except worm tooth profile. It is considered that the worm tooth profiles show a higher effect on the fatigue life because the DR type actuators are smaller than the L type actuators. The actuator ratings should be designed higher than the certified torques and performance margins. However, some ratings calculated are not higher than the certified torques and performance margins. It is considered that the calculated actuator ratings are highly conservative. In spite of the high conservatism, the actuator rating calculation is useful for implementing GL 89-10.

4. Conclusion

The TTS test experience for non-Limitorque actuator has been described in this paper. The actuator capability was assessed with the direct and indirect method. The results indicate that the real actuator output torques for Joucomatic actuator models (80L111, 80L20, DR10.35, DR10.58, DR40.72, and DR5.58) are 20%~100% greater than those of design basis review. For EIM-30 model, the real actuator torques are very close to the design basis actuator torque.

The calculated rating torques are different from the certified torques and the performance margins. Testing for the actuators is required to demonstrate higher rating torques.

In spite of the high conservatism, the actuator rating calculation is useful for implementing GL 89-10.

As a conclusion, we could improve and confirm some non-Limitorque actuator capabilities by introducing the TTS and the actuator rating analysis.

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Table 1. Actuator manufactures in Korea NPPs

Unit \ Manufactures		LI*	JO*	EIM	HO*	RO*	AO*
Kori 1&2		117			18		
Kori 3&4		218				4	
Youngkwang 1&2		218				4	
Youngkwang 3&4		200				37	
Ulchin 1&2			88				
Ulchin 3&4		57				55	9
Wolsong 1		47		19			
Wolsong 2,3,4		96				99	12
Total	Quantity	953	88	19	18	199	21
	(%)	73.4	6.8	1.5	1.4	15.3	1.6

*LI: Limitorque, HO: Hopkinsons, RO: Rotork, AO: Autotork, JO: Joucomatic

Table 2. Actuator models tested with TTS

Unit	Manufacture	Model	Method
Ulchin 1&2	JO	80.L.111	indirect
		80.L.20	
		DR.10.35	
		DR.10.58	
		DR.40.72	
		DR.5.58	
Ulchin 3&4	AO	NQ60	indirect
Wolsong 1	EIM	EB-30	direct

Table 3. Actuator output torque (ft-lbf) with design basis review

Actuator model		Voltage condition		
		80%	90%	100%
JO	80.L.111	227.8	242.0	255.7
	80.L.20	457.4	561.3	670.4
	DR.10.35	73.8	73.8	73.8
	DR.10.58	161.9	191.7	223.0
	DR.40.72	22.8	28.9	35.7
	DR.5.58	46.4	58.5	72.0
AO	NQ60	-	44.7@ 97.8%	-
EIM	EB-30	-	142.5@97.8%	-

Table 4. Actuator output torque (ft-lbf) with TTS test

Actuator model		Voltage condition		
		80%	90%	100%
JO	80.L.111	455.2	-	-
	80.L.20	860.6	864.1	-
	DR.10.35	131.2	142.3	164.6
	DR.10.58	240.1	237.3	246.8
	DR.40.72	-	39.2	46.0
	DR.5.58	-	95.0	100.0
AO	NQ60	-	26.17@95.6%	-
EIM	EB-30	-	147.5@98.2%	-

Table 5. Actuator rating analysis results

Actuator Model	Maximum Torque (ft-lbf)	Certified Torque (ft-lbf)	Performance Margins (ft-lbf)	Calculated Torque Rating (ft-lbf)
DR 5.35	51.0	36.6	50.5	160.0
DR 5.58	25.0	25.6	-	100.0
DR 10.35	60.2	73.2	150.0	160.0
DR 10.43	41.0	73.2	116.3	160.0
DR 10.58	81.1	58.5	95.8	100.0
DR 20.35	204.1	146.3	338.0	300.0
DR 20.43	138.6	146.3	261.9	270.0
DR 20.72	102.4	87.8	150.7	310.0
DR 20.88	80.9	73.2	120.7	220.0
DR 40.35	35.4	292.6	663.5	350.0
DR 40.72	187.3	175.6	299.9	260.0
80L 20	496.7	512.1	848.5	750.0
80L 111	563.0	234.1	417.0	740.0
100L 89	1052.8	438.9	899.7	1450.0
125LS 19	1514.4	2231.1	3686.8	2250.0
125L 47	1978.6	1389.9	2787.0	2300.0

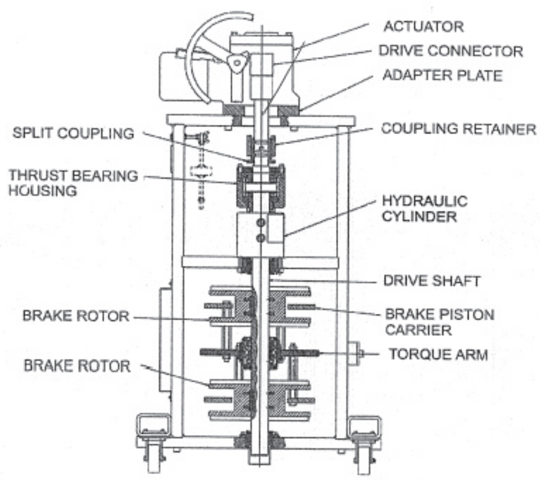


Figure 1. Outline of TTS equipment

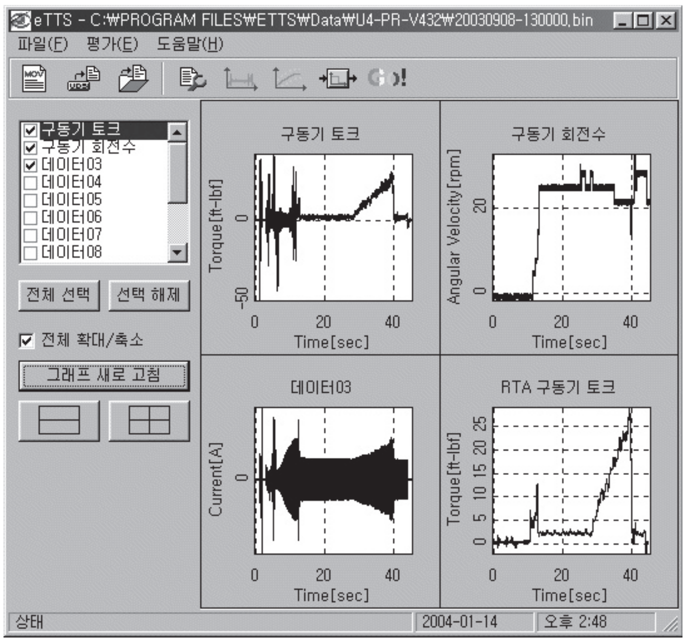
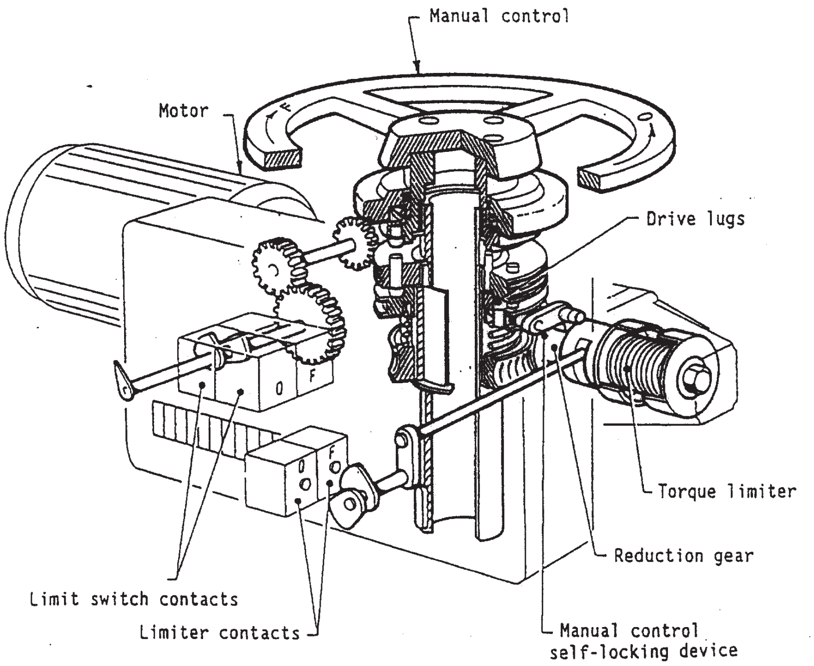
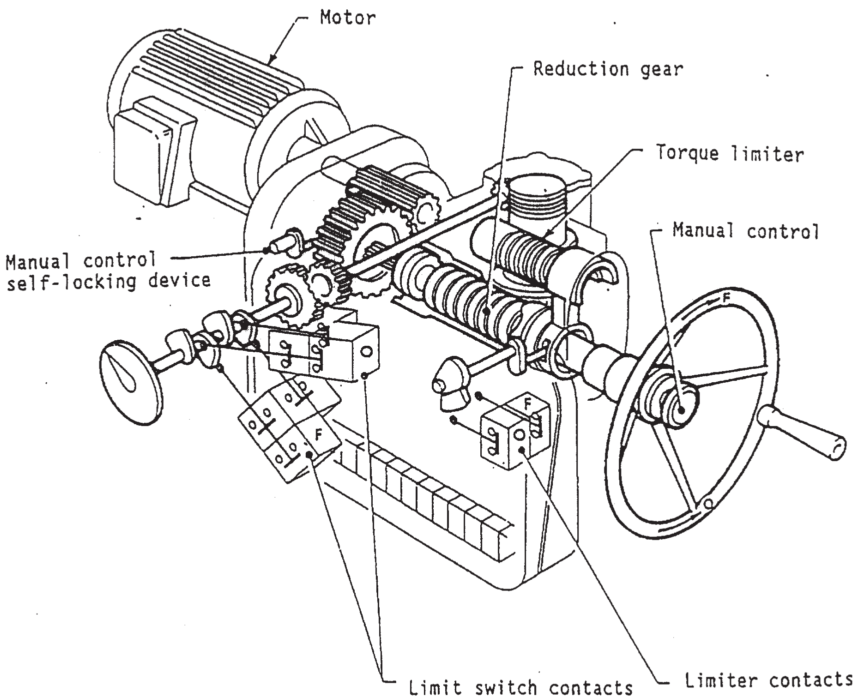


Figure 2. Outline of eTTS program

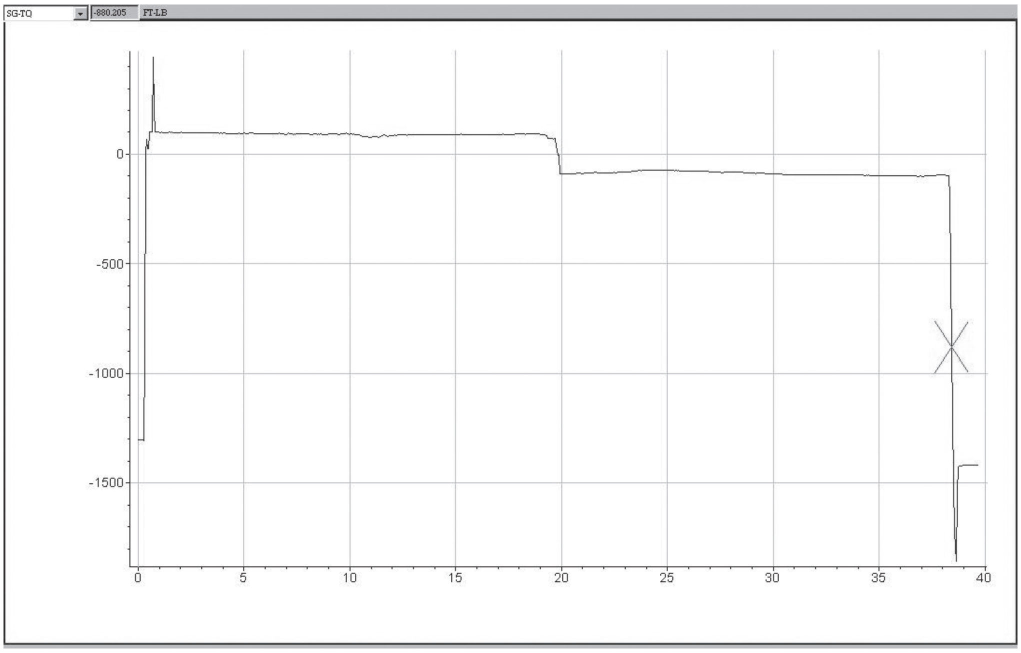


(a) DR type Joucomatic actuator

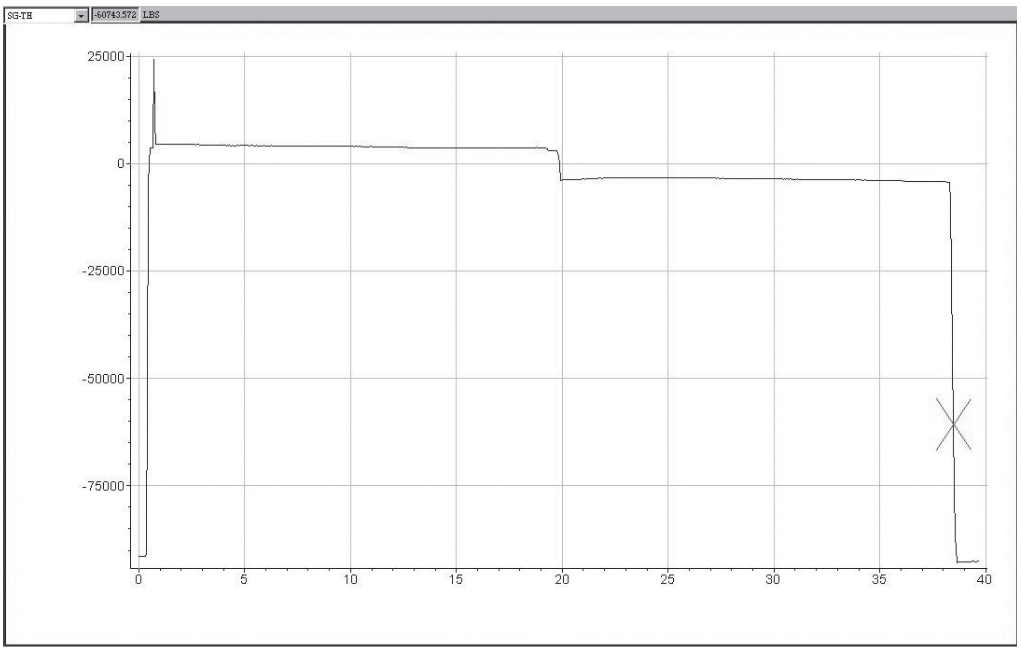


(b) L Type Joucomatic actuator

Figure 3. Joucomatic actuators



(a) A typical torque ramp for Joucomatic actuator



(b) A typical thrust ramp for Joucomatic actuator

Figure 4. Typical valve torque curve for static test

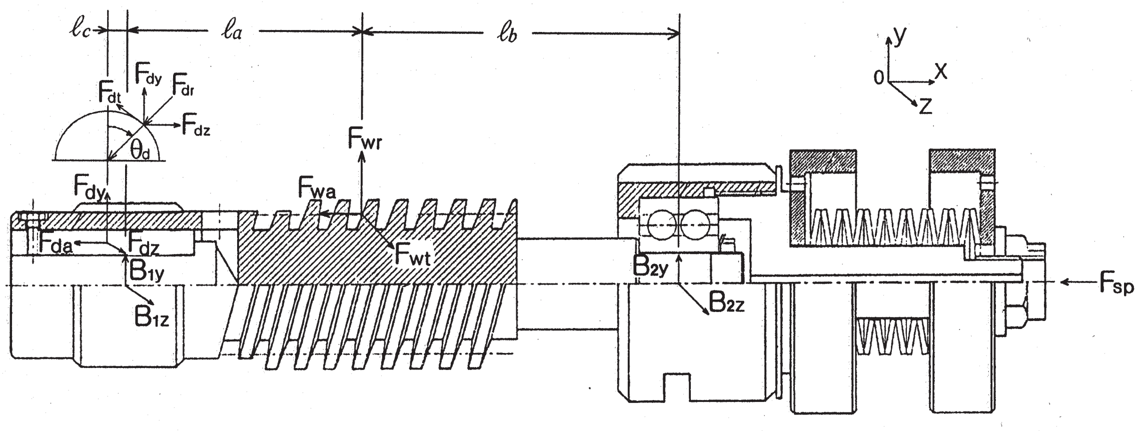


Figure 5. Analysis model for the actuator shaft with worm

Upgrading to Digital Positioners on Feedwater Regulating Valves

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Abstract:

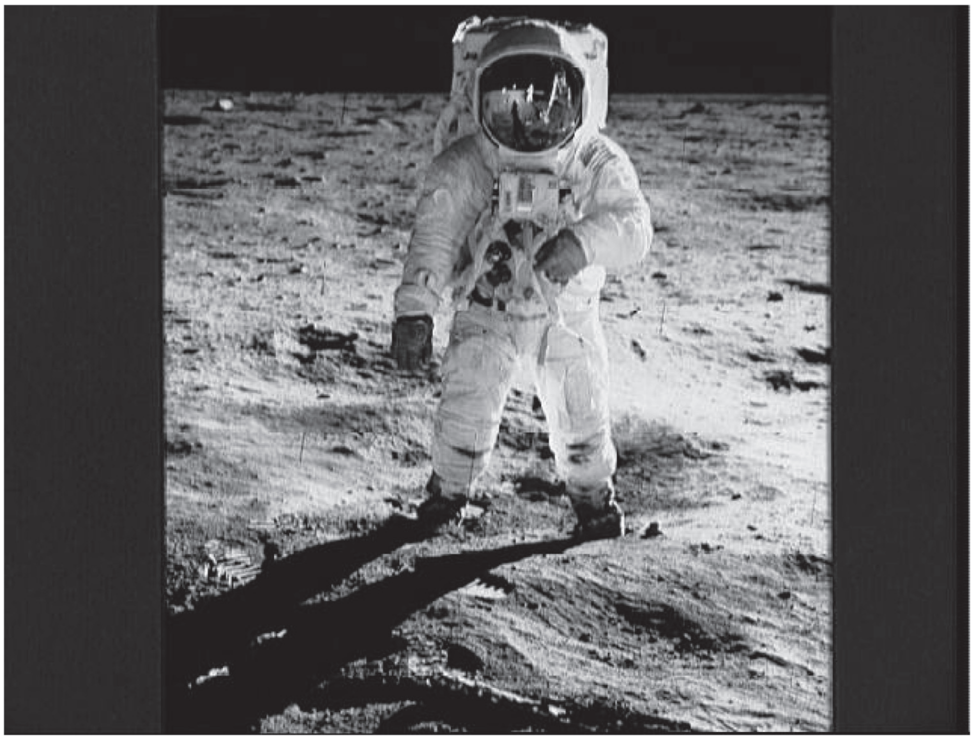
Fort Calhoun Station experienced reliability problems with the Feedwater Regulating Valves.

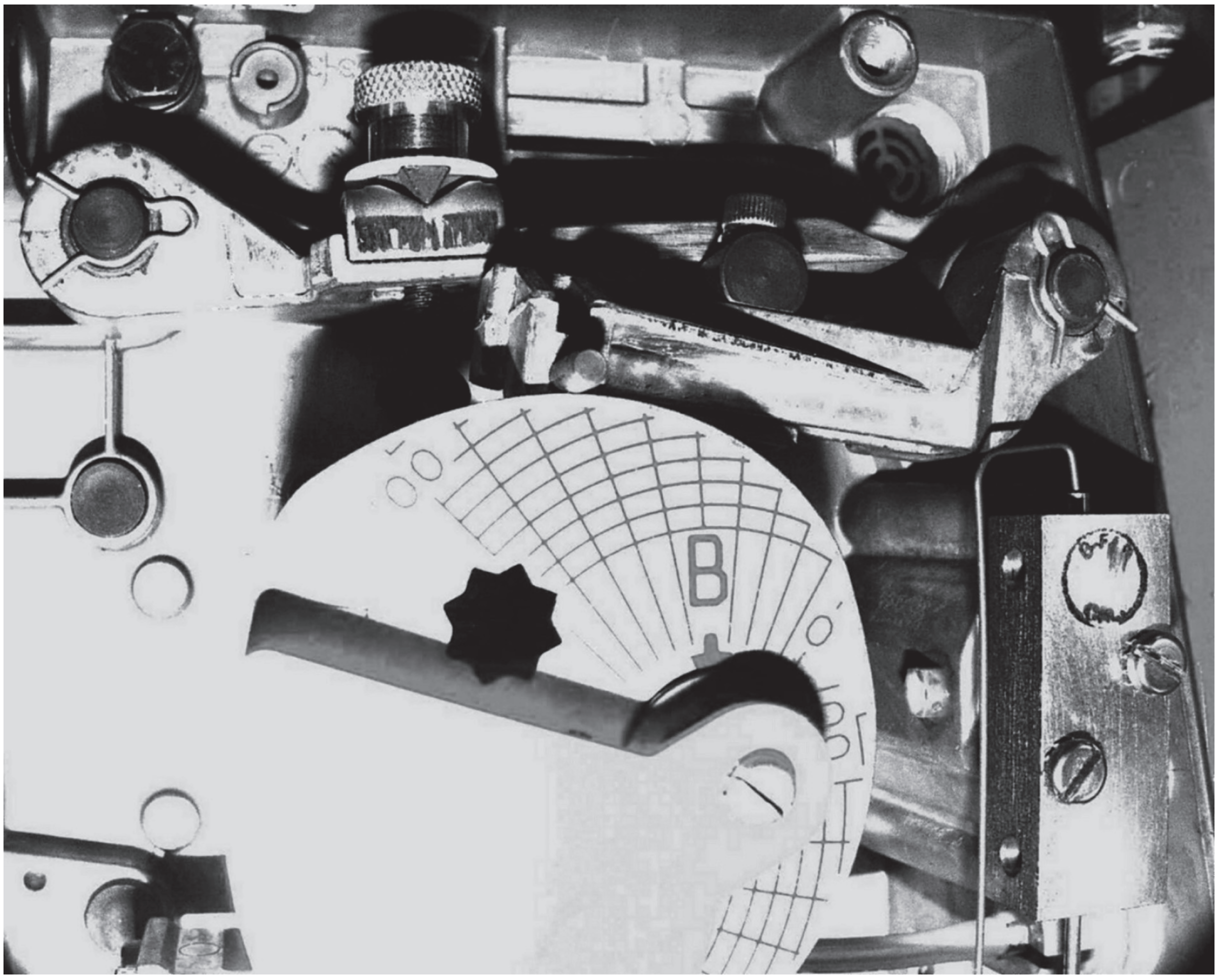
The Steam Generator Level Control System provides a 10 to 50 milliamp (ma) signal to a Fisher Model 546 positioner. The single pneumatic output of the Fisher positioner feeds into a Bailey Model AV1 positioner to provide a dual output to a Fisher Type 472, Size 80 piston actuator. Similar designs are used in the nuclear industry.

The lever arm in the positioner has a ball bearing mounted on a shaft which rides as a wheel on the positioner cam. The retaining clip which holds the ball bearing in place vibrated off allowing the ball bearing to fall off causing the shaft to ride directly on the cam. A plant shutdown would be necessary to fix the problem.

Positioner problems such as spool valve fretting, feedback arms and linkages have been

an ongoing issue in the Nuclear Industry. The decision was made to look at new technology in an attempt to eliminate the problem(s). The option of a digital positioner was selected for the upgrade. Several features such as remote mounting capability, on board diagnostics capability and allow integration to a future Digital Process Control System modification at Fort Calhoun Station. Based on the experiences at Fort Calhoun Station and discussions with plants installing digital positioners on Feedwater Regulating valves many of the challenges were similar. This presentation is important because some of the issues were technical in nature but many revolved around cultural paradigms and work practices. To gain the full advantage of equipment upgrades such as this one, one must be ready to address culture and to change work practices.





Background:

On January 23, 2001, a reactor operator at Fort Calhoun Station received a RC-2A S/G High Level Alarm. The reactor operator notified his supervisor that the automatic control mode of the flow control loop was not functioning properly. The flow control loop was taken from automatic to manual mode and a plan to troubleshoot the problem was formulated. A 22 percent step change in valve position was observed on the Feedwater Regulating Valve (FRV) after trouble shooting. The FRV was returned to automatic mode after the positioner problem was better understood until the next refueling outage. During the refueling outage the positioner cover was removed and it was determined that the retaining clip came loose and the cam roller was found lying in the cover.

On August 26, 2003, a reactor operator received a RC-2A S/G LOW LEVEL ALARM. It appeared the FRV was not responding in automatic mode. The operator restored level control by shifting FRV control from automatic to manual mode. While restoring steam generator level the plant experienced a slight ***reactor power transient***. This was a second occurrence at Fort Calhoun Station.

After generically looking at common industry operating experience problems with positioners such as age degradation, air leaks, linkage and positioner problems, the decision was made to evaluate upgrading the positioners to enhance reliability. Upgrading a positioner sounds like an easy task on the surface but it is not; this experience provided many interesting challenges which are shared in this paper. The importance of this paper is to acknowledge changes in process control technology that may impact utilities wishing to upgrade to digital controllers in the future.

Positioner Failure

The picture above illustrates typical technology used by many manufacturers in the process control industry over the past several decades. A lever arm has a ball bearing (not shown) mounted on a shaft which rides as a wheel on the positioner cam. In this case a retaining clip most likely vibrated loose allowing the ball bearing to fall off causing the shaft to ride directly on the cam. This causes a shift in the feedback within the device which makes the positioner think that the valve is in a different position and results in a corrective action from the positioner. At Fort Calhoun Station this caused the level in the steam generator to shift followed by a slight system transient.

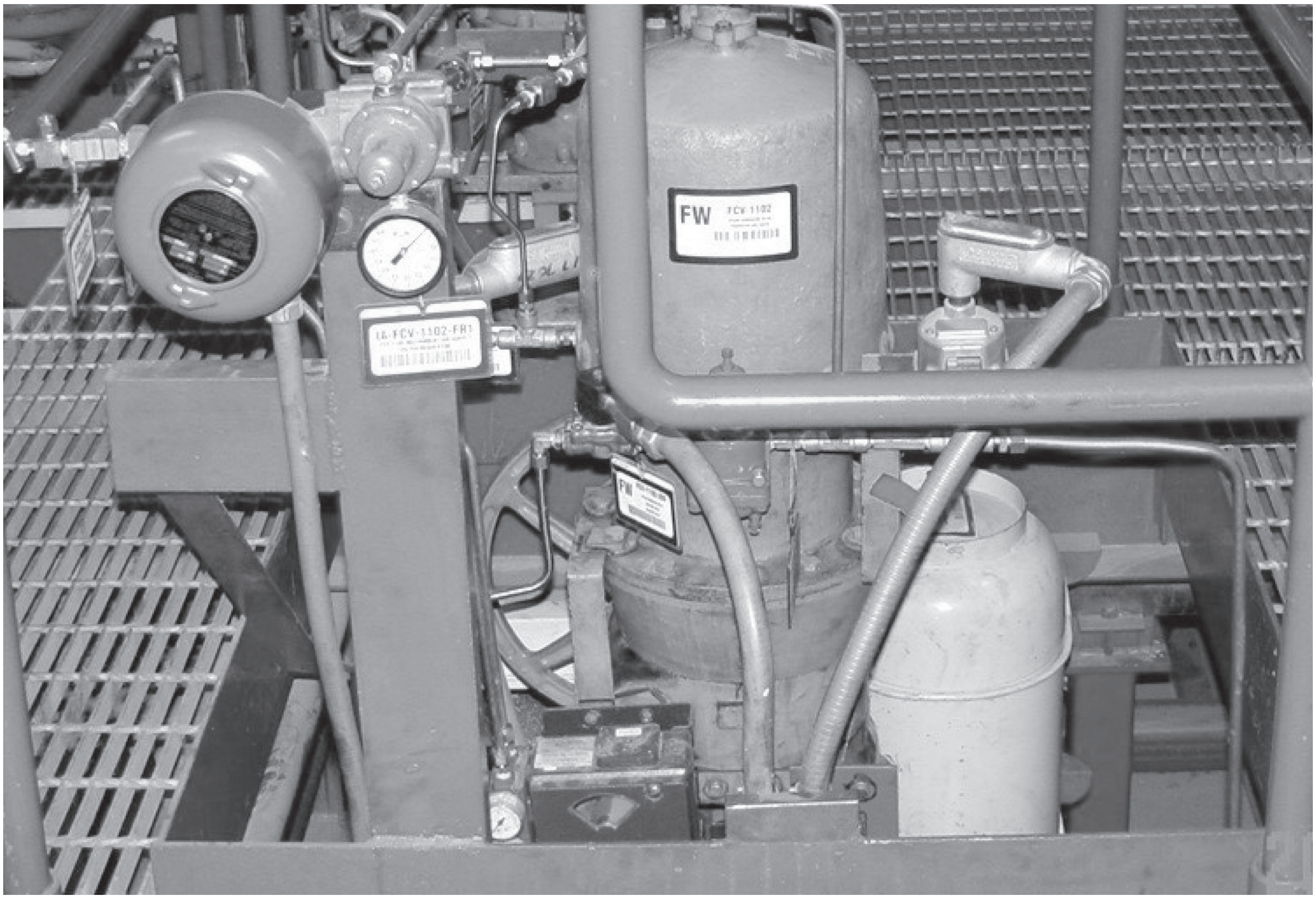
Original Air Operated Valve Configuration:

Actuator: Fisher Type 472-1 Size 80,
Piston without Spring

Valve: Fisher Model EHD
Size 8 inch with travel limited to 3.5 inches.

Positioner: Fisher Model 546/Bailey Model AV1
10 – 50 ma input
3 – 27 psi output

The pneumatic output signal was fed into a Bailey positioner to convert the single output to a double output for a piston actuator.



Reliability Issue:

FCS experienced valve positioner problems impacting plant reliability. The positioner was subjected to vibration which created continuous problems such as maintaining calibration and cam follower roller bearing failure. Discussion with other plants in the industry also identified positioner linkage and fretting problems in the sliding spool control valve assembly within the positioner potentially resulting in degraded valve control performance or a possible plant trip.

Bailey Positioner

Choosing a new positioner for the Upgrade:

The decision was made to investigate use of new technology available to increase plant reliability. Challenges for upgrading the positioners existed in many areas so we looked from the inside of the box to the outside.

- **Cultural Change**s (Engineering, Craft and Operations)
  - ❑ Site engineering experience with digital technology was very limited and plant procedures were not in-place to evaluate digital modifications.
  - ❑ Craft and Operations personal had no experience with the digital positioners or the associated software
  - ❑ Training and experience would be needed for everyone. Experienced on-site staff did have the appropriate level of knowledge for digital positioners.
  - ❑ Culturally there was concern about the **"Digital Scare"** problems heard in the industry over many years and the possibility of malfunctions during the installation of the modification and post maintenance during plant startup & operations.

Advantages

- The digital positioners selected have the capability to perform advanced diagnostics which almost eliminated the need for conventional diagnostic test equipment.
- Historical data could be retrieved after the installation of a Digital Process
- Control System from a remote location.
- The issue of man machine interface when performing calibration is addressed. The results will be the same as long as the same data is used.
- Local and Remote mounting capability eliminates leakage adjustment which could affect calibration.
- Maintenance time required for calibration, and maintenance was significantly reduced. In addition, removal for a remote mounted digital positioner for valve and actuator overhauls takes only a few minutes.

Modification Process:

Evaluation of Digital positioners

- Evaluation Procedures – Outside assistance was obtained to develop procedures to document and evaluate digital process controls that utilize microprocessors, associated software/firmware to perform its intended design function. This process was based on available industry information from EPRI Report TR-102348, "Guideline on Licensing Digital Upgrades."
- Learning new technology – Several digital positioners were considered. The following features were looked at to make a final decision
  - ❑ Robust construction and a product that was easy to maintain
  - ❑ Positioners with on-board diagnostics capabilities and characteristics that were similar to diagnostic test equipment currently used in the nuclear industry
  - ❑ Vendor Support for Training with minimal costs to the station
  - ❑ Positioners that would be compatible with new digital plant architectures in the future and that had a significant installed base within the process control industry.
  - ❑ Ease of installation, testing and calibration
  - ❑ Capable of being remotely mounted to avoid harsh environments during maintenance, normal operation and accident conditions.

Modification Issues

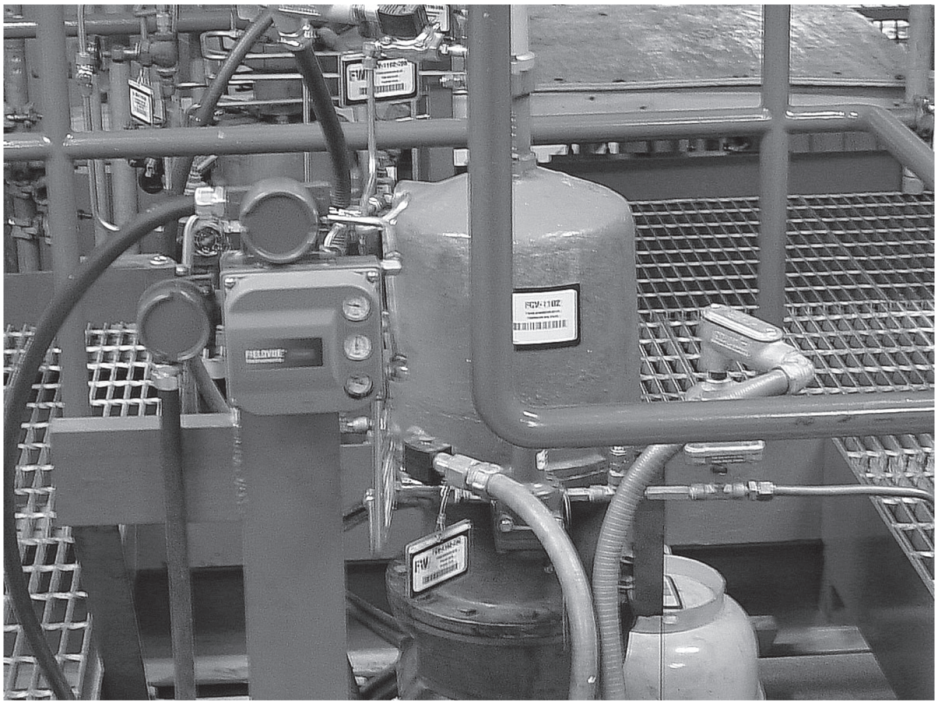
- Converting the process control signal from 10 – 50 ma to 4-20 ma.
  - ❑ A signal conditioner was installed in remote panels to convert the signal to 4-20 ma.
- Testing
  - ❑ Testing requirements had to be established.
  - ❑ Portable diagnostic Test Equipment was used to validate On-Board diagnostic dynamic and ramp test capability of the digital positioner.
  - ❑ Plant calibration procedures were revised.
- Training and Experience
  - ❑ I&C Technicians and Training Department personnel familiar with air operated valve diagnostics were trained by the vendor on digital positioners and associated software.
  - ❑ Vendor experience was used during the installation and validation testing. This included pre-outage walkdowns and checking out the positioner in the I&C shop to ensure itoperated correctly and to familiarize plant personal with test equipment and software.

- Component Testing and Design Engineers benchmarked similar modifications at a site and participated with the installation of digital positioners with the vendor. This provided engineering knowledge and experience required for preparation, procurement and installation of the digital positioners. In addition, experience was obtained for initial setup and calibration to develop changes to plant procedures and the modification package.

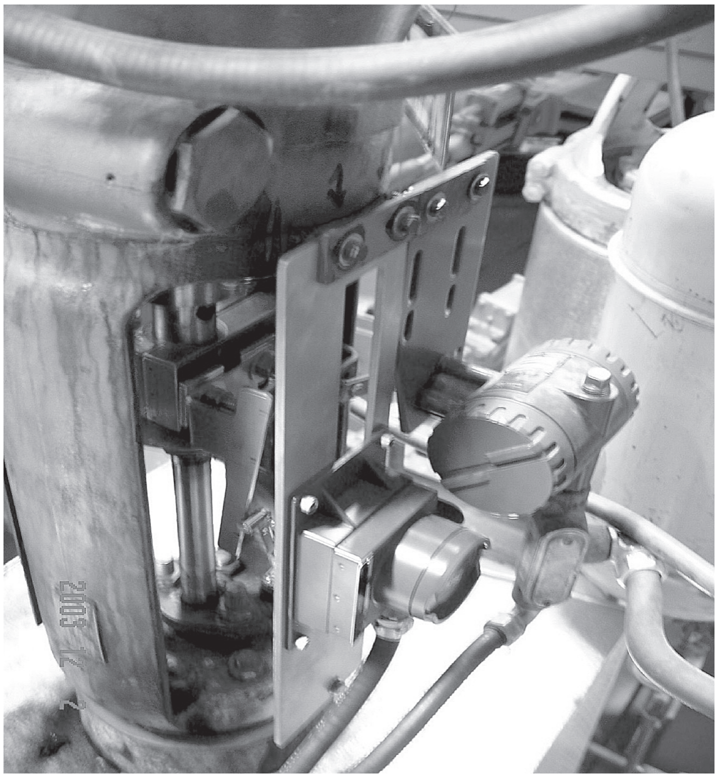
Diagnostic Testing with On-Board Diagnostics and AOV Diagnostic Test Equipment.

- The Feedwater Regulating System utilizes a three element control loop with inputs from feedwater flow, steam flow, and steam generator Level. It controls the FRVs at 70% open (Equivalent to 100% Power) to maintain the steam generator programmed level at 65%.
- In the event of a turbine trip, a ramp signal will close the both FRVs from 70% open (100% Power) to 8% (5% Power) open in 20 seconds.
- Fisher ValveLink Software was used to setup the digital positioner on the Air Operated Valve. In addition the Hart communicators were used to ensure that the positioner would perform similar tasks, as part of an equipment check.
- Diagnostic tests were compared using Fisher Flowscanner 5000 diagnostic test equipment to validate the signatures from the AMS ValveLink Software.
- The Loop Calibration Procedures were used as a final check for Post Maintenance Testing and returning the loop to operation.
- Diagnostic Testing was performed to verify AOV setup parameters such as:
  - Valve stroke length
  - Tuning Setup
    - Proportional & Integral gain settings
    - Dynamic error and linearity
    - Zero and Span at full range of travel
  - Packing friction
  - Overall dynamic valve signature comparison between Fisher Flowscanner and AMS ValveLink Software.

Installation of the Digital Positioner



Installation of the Mounting Bracket and Travel Potentiometer for the Digital Positioner

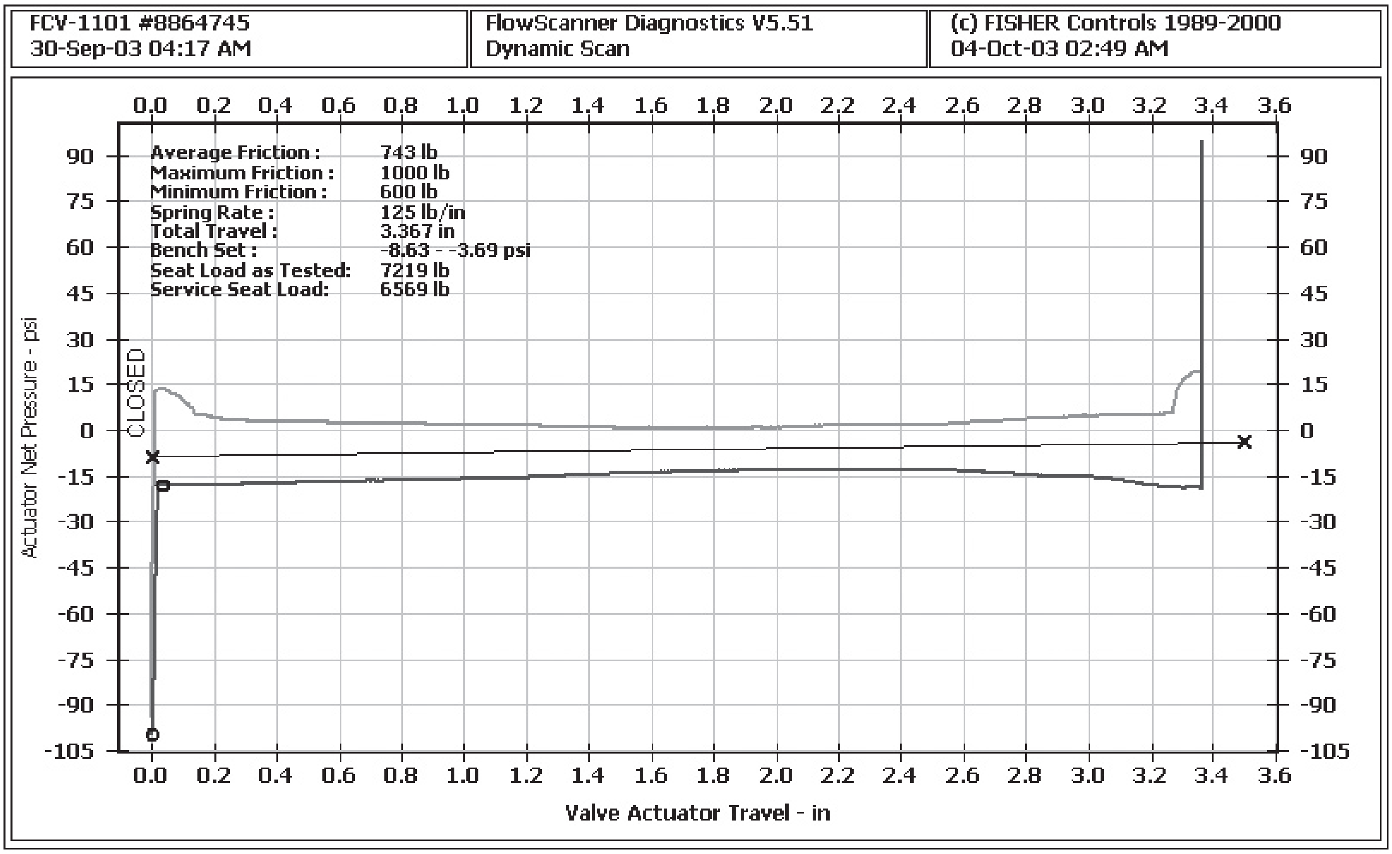


Installation of the Cam and Travel Potentiometer for the Digital Positioner

(Side View)

Dynamic Scan Test

Flowscanner Diagnostics



Test Conditions:

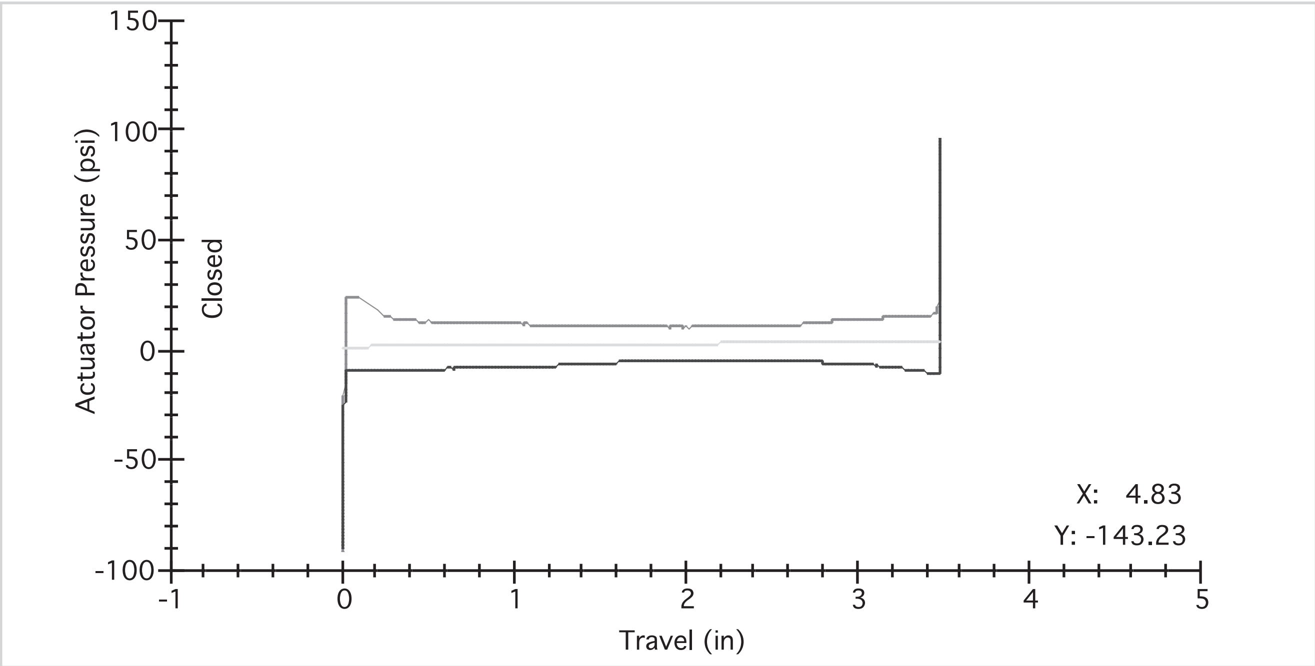
Dynamic testing was performed with the Plant shutdown under Flow conditions.

The top trace going from left to right illustrates the valve going from closed to the full open position.

The bottom trace from right to left illustrates the valve going from full open to the closed positioner.

Dynamic Scan Test

ValveLink Diagnostics



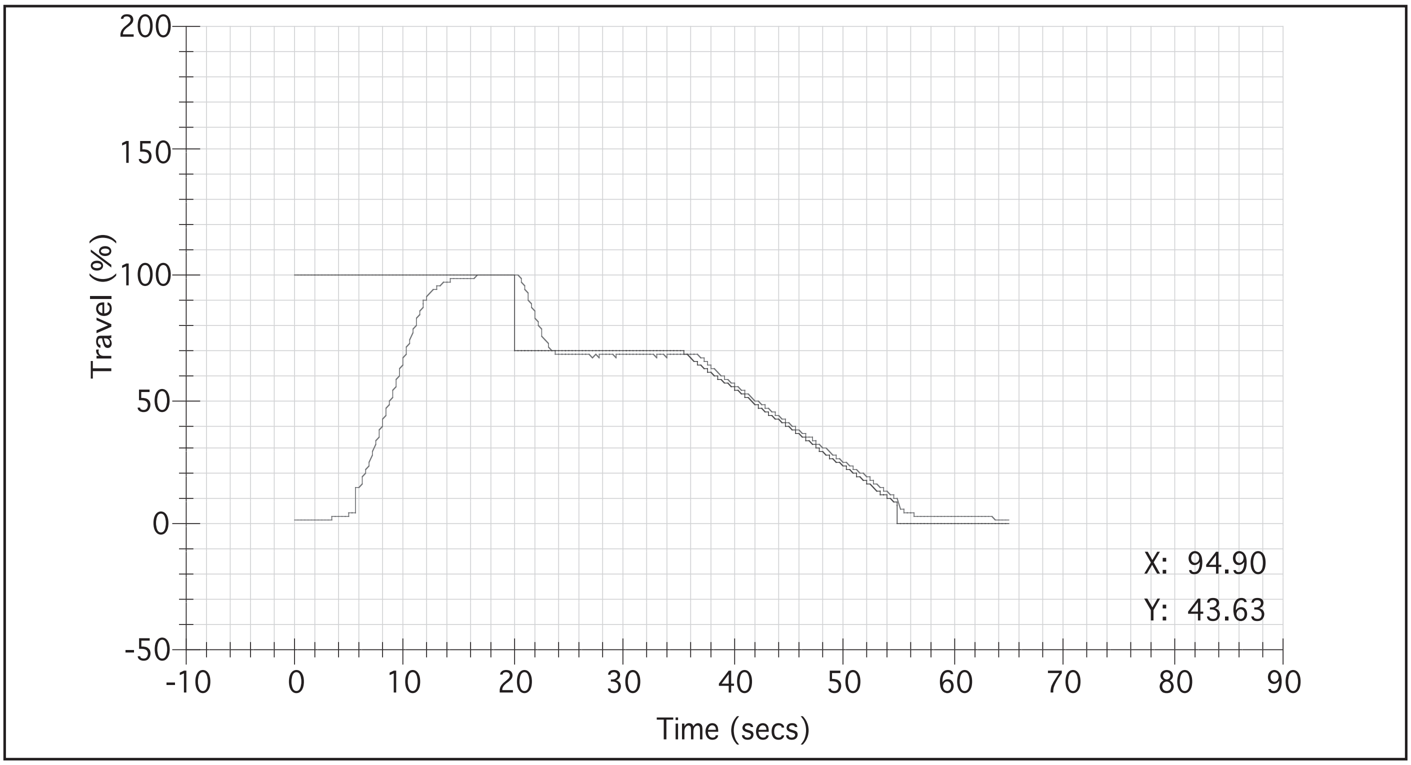
Valve Travel – Closing Stroke (bottom trace)

Valve Travel – Opening stroke (top trace)

The profile characteristics of both Dynamic Signatures from the AMS ValveLink and Flowscanner diagnostics were compared. The comparison demonstrated that the on-board advanced diagnostics in the digital positioner were functional. The intention is to use the On-Board diagnostics in place of the Flowscanner.

- Calibration time for the positioner was reduced from 4 hours to 5 minutes per valve.
- The need to disconnect tubing and lifting leads was eliminated.
- Repeatability for calibrations no longer a concern with digital positioners even when different technicians perform the positioner calibrations.

RAMP Test Simulation from 100% to 5% Power



Ramp Input Signal – top trace

Valve Travel – bottom trace

Ramp testing was performed with the plant shutdown and no process flow from 70% to 8% open within 20 seconds using the AMS ValveLink Diagnostics to ensure the valves would respond to a turbine trip.

- This was done by simulating 100% open full valve travel followed by a step to 70% open (100% Power) to set up the test.
- The air operated valve was stabilized prior to initiation of a 20 second ramp signal from 70% open to 8% open (5% Power).

- Each Feedwater Regulating Valve was returned to service after a Loop Calibration and a function check to cycle the valve.

New technology requires new training

- Knowledge and experience was obtained by working with Emerson Process Controls personnel during an installation of digital positioners at Omaha Public Power District's North Omaha Station.
- Vendor manuals for the positioners and software were obtained in advance to assist Design Engineering with the development and planning of the modification package.
- Site Engineering, Training and I&C personnel attended training at Fisher in Marshalltown prior to the development of the modification package. This was very beneficial in helping everyone understand the installation and calibration of the positioners.
- The digital positioner and software was setup in the I&C shop to perform a functional check of the positioners and test equipment prior to installation in the field. This mock-up significantly reduced hardware installation and software/hardware setup time. In addition this task verified everything was working before the installation.

Potential Benefits:

While the focus on this project was on increasing hardware reliability, there are additional benefits that can result from leveraging this type of technology. These benefits include:

- Faster more stable valve response will enable loops to be tuned and set up closer to operating limits increasing overall output and efficiency. i.e. The plant will generate more megawatts.
- More stable operation of the valves will result, given the capability of the positioner, which will reduce the wear and tear on the valve and major system components that might have to react to variations of flow through the valve. A smoother plant runs better and cheaper with reduced need for corrective maintenance spending.
- Upgrading to modern equipment addresses the issue of equipment obsolescence and technical support.
- Online diagnostics capability will permit a condition-based predictive maintenance approach on the Feedwater System, resulting in better performance at a lower cost.
- Digital equipment can be tuned to match the operating requirements of the system, optimizing process control. This translates into improved plant performance at lower cost as previously mentioned. If necessary, it could be tuned to match the performance of the equipment that it replaces so that the system would not have to be retuned until more experience is gained by the plant.
- Digital upgrade with advanced diagnostics and communications capabilities provides an avenue of transition to future Digital Process Control Systems which will improve plant performance and reduced maintenance. Plant personnel will have remote calibration and monitoring capabilities for component and system performance.

10 Top Things to Consider When Upgrading to Digital Positioners:

1. Develop good communications to ensure the manufacturer understands everything about the application.
2. Make sure all personnel on site participating are familiar with the Digital Upgrade.
3. Ensure your vendor has the knowledge, experience and enthusiasm to work through every phase of the modification.
4. Consider using alternative testing with additional equipment to validate on-board digital diagnostics.
5. Setup and test equipment prior to the installation to ensure everything is operating correctly.
6. The modification process should carefully address all the issues for digital modifications by using available industry guidelines and practices.
7. Obtain training directly from the manufacturer for various plant personnel, such as Design, Training and Craft personnel.
8. Have spare parts and equipment readily available to prevent delays.
9. Participate with a cross section of personnel for the installation of digital controls at another site(s) to learn as much as possible.
10. Attend industry conferences and use resources for industry operating experience information to understand potential problems associated with conventional and digital positioners.

Quote of the Day:
"There are no Bad Positioners, it's just that some work better than others."

References:

Control Valves for the Chemical Process Industry McGraw-Hill 1995, Author: Bill Fitzgerald

The Control Valve's hidden impact on the bottom line" Part 1 and Part 2. Valve Magazine, Summer and Fall, 2004 issues Author: Bill Fitzgerald and Chuck Linden

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Use of Graphitic Pressure Seal Ring Gaskets in Pressure-Seal Bonnet Designed Valves

Bruce Harry
CRANE Nuclear, Inc.

In recent years, the momentum for the use of (Die-Formed) Graphitic Pressure Seal Rings in Pressure-Seal Bonnet designed valves has increased. CRANE Nuclear experiences with Graphitic Pressure Seal Rings started in 1994 and, from the onset, had developed a methodology to evaluate each application. CRANE Nuclear's evaluation process, analysis techniques, lessons learned, installation procedures, applications where Graphitic PS Rings were not recommended, and future development activities, will be discussed during the Symposium presentation.

Pressure seal ring gaskets manufactured from graphite are typically furnished as replacements for the originally supplied metallic materials with silver plating. The advantage of the seal ring manufactured from graphite is its inherent property to better conform to mating surfaces, and will seal even if small imperfections in the sealing surfaces are present.

Two separate characteristics which must be addressed are: 1) the tendency for the graphitic material to consolidate; and 2) when under pressure, to flow. Consolidation affects the initial height of the graphitic Seal Ring set; therefore, mechanical fit-ups must be reviewed to determine dimensional limits for installation and subsequent retightening. It is the tendency for the graphitic material to flow, that requires special provisions for field retrofitting. Each graphitic Seal Ring set consists of a stainless steel Backing Ring. This Backing Ring is placed directly on top of the Seal Ring. The Backing Ring is sized not only to prevent the graphitic material from extruding between parts, but can also be designed to limit the amount of consolidation.

For field retrofitting, the graphitic Seal Ring (with the Backing Ring) is designed to be a direct replacement for the existing metallic Seal Ring, without changes to any of the mating parts, and would not affect the pressure and temperature rating of the valve.

Unlike graphitic gaskets used in Bolted Bonnet design valves, which only perform a sealing function, the Pressure-Seal Bonnet Gasket is designed also as a structural component.

The Pressure Seal Ring Gasket not only affects the alignment of the Bonnet, but is a load path member, directly transmitting the line pressure load to the Retaining (or Segment) Ring, a valve pressure boundary component. For this reason, the substitution to graphitic Pressure-Seal Rings must be carefully evaluated for each application.

Programmatic Approaches to Ensuring Appendix J Leak Tightness Following Maintenance Activities

William A. Loweth
Millstone Power Station
Dominion Nuclear Connecticut, Inc.

Abstract

The presentation will focus on a programmatic approach to assess the overall health of a typical 10 CFR 50 Appendix J valve/penetration assembly, exploiting the interrelationships of Appendix J, inservice testing (IST), Work Planning, motor-operated valve (MOV), air-operated valve (AOV) and other programs. One of several rational approaches to extending Local Leak Rate Tests (LLRTs) up to their next periodic test interval following "mid-cycle" minor maintenance activities, that could affect a valve's leak tightness, will be shown for discussion purposes.

Introduction

10CFR50 Appendix J states, "One of the conditions of all operating licenses for light water cooled power reactors…is that primary reactor containments shall meet the leakage-rate test requirements in either Option A or B of this Appendix." Option B of this Appendix identifies the performance-based requirements and criteria for preoperational and subsequent periodic leakage rate testing. Specific guidance concerning an Option B performance-based leakage test program, with acceptable leakage rate test methods, procedures and analysis are provided in Regulatory Guide 1.163, "Performance Based Containment Leak Test Program."

A review of Regulatory Guide 1.163 indicates the NRC's acceptance of Nuclear Energy Institute (NEI) Industry Guideline NEI 94-01, Rev. 0, for implementing the performance-based option of 10CFR Part 50, Appendix J. With the exception of some Containment Purge and Vent Valves on Pressurized Water Reactors (PWRs), and Main Steam Isolation and Feedwater Isolation Valves on Boiling Water Reactors (BWRs), the Option B process permits extended test intervals up to 60 months.

For penetrations to qualify for this extension of the test interval, NEI 94-01 states "extensions to Type B and Type C test intervals are allowed based upon completion of two consecutive periodic as-found tests where the results of each test are within a licensee's allowable administrative limits. If the test interval for Type C test is at 30 months; it may be increased to 60 months. If the Type C tests are not acceptable, the test frequency should be set at the initial test intervals. Once the cause determination and corrective actions have been completed, acceptable performance may be reestablished and the testing frequency returned to the extended intervals as specified in this document."

Programmatic approach to ensuring Appendix J leak tightness

So where are we headed with this? Many Utilities are working toward, or have been given, approval to follow the rules of Option B, and to maintain a 30 to 60 month test interval between LLRT type C tests. This risk-based approach makes sense. If the penetration is performing well over time, with repeatable results, AND work activities on components that make up the penetration are assessed for impact and controlled, it is reasonable that the overall "health" of the penetration be maintained between extended LLRT testing intervals.

In years past, Utilities would not second-guess whether the impending work would require an as-found LLRT before they touched the penetration's isolation valves. An as-found LLRT would be performed if there was even a hint the impending work could "disturb" or affect the penetration's ability to perform under design basis loss of coolant accident (DB LOCA) conditions! What would happen if an unexpected work activity on the penetration assembly were to occur between these extended LLRT test intervals? During this period, there appeared to be no clear or agreed to guidance on what was an acceptable work activity that would not affect the penetration's "health", leaving many Utilities to their own devises. The Regulatory Guide and, even more so, the NEI document were fine for describing the means to extend test intervals. But little guidance existed for Utilities to make a conscious and consistent determination to conclude when a LLRT was necessary depending on the work activity. The standard, conservative decision was that the work activity would jeopardize the penetration's "health"! With the onset of more Utilities planning work around specific safety equipment trains during alternate outages, making educated decisions to justify deferring LLRT testing following minor maintenance becomes more important.

In 1995, the BWROG VTRG (Boiling Water Reactor Owners' Group Valve Technical Resolution Group) proposed a rational approach to help Appendix J engineers assess the need to perform LLRT tests at the onset of minor work activities. (Excerpts are provided at the end of this paper as Enclosure 1). With the onset of Generic Letter 89-10, motor operated isolation valves began to be tested for closing and opening capability. Actual repeatable thrust values were being obtained. Diagnostic test data began to give the MOV engineers the "uncanny ability" to make a prediction of a valve's seat condition.

Now for the hard part; do you think it is possible to convince the Appendix J engineer that the valve/seat profile looks pretty basic, the thrust is fairly repeatable between tests… would you think there is a possibility the penetration assembly, consisting of 2 to 3 MOVs, relief valves and manual isolation valves, would still be a good penetration, after the MOV guys had to change out a torque switch????? If we were to diagnostically test an MOV, then take the actuator off its yoke, walk it around containment, bolt it back on, diagnostically retest it and leave the thrust practically where we found it, I would be comfortable in telling Operations the penetration leakage rate would be practically the same.... but would they believe me??

Now, put yourself at a "Mid Cycle" point, you have a good penetration that has passed 2 consecutive tests (worthy of going to 60 months), and "Oh oh! We have to change out the torque switch!!!" Now, how do you get to the next LLRT test interval without an LLRT? In the past (pre-1995), we would, without question, LLRT the penetration, no matter what the MOV guys told us! This would apply to packing changes, limit switch adjustments, etc.

It is at this juncture we want to apply engineering analysis methods, and provide examples of what that review may entail, to support a conclusion that the penetration exhibits good or bad performance. If it is a good performer, provide the justification to not LLRT a penetration in "Mid Cycle".

Taking various pieces of information and data from several in-house programs, a work history review of the penetration would look for a correlation of penetration leakage performance, past work history, and adjacent containment isolation closing thrust performance over time.

Enclosures 2 and 3 are history reviews of 2 penetration assemblies at Millstone Unit 3. The examples illustrate several factors to consider in assessing the health of a penetration. From a review of past work history over the years, one can assess whether, outside of LLRT "space", there may be other factors – packing leaks, MOV gear changes, AOV diaphragm/spring change outs, disk/wedge replacements, as well as valve size, manufacturer, style, safety significance [including a review of core damage frequency (CDF) and large early release frequency (LERF) (which you can get from your probabilistic risk assessment (PRA)/Safety analysis folks) and configuration (horizontally mounted, or vertically mounted), service conditions and fluid media]. Couple this to the history of the penetration's LLRT performance and MOV/AOV thrust data can provide a clear picture of how the penetration has behaved over time. It is at this juncture the Appendix J Engineer can make some reasonable judgments as to how the penetration is affected by different minor maintenance activities.

For example, if further review of the work activities and performance of the associated valves show that, if the closing thrust remains pretty much the same and the penetration is a good one, you have reasonable assurance the penetration is OK. If you put the total thrust back to the as-found condition, you should be able to hold off on the official LLRT test until the next scheduled test interval. Where this approach benefits the utility is in the case of a packing adjustment/changeout during a cycle. This approach could also apply to the replacement of closure springs on an AOV, if subsequent testing can show a closing thrust of similar magnitude is repeated after the change, and the valve strokes consistently.

Qualitatively, it is best to review the resulting performance of all penetrations after outage work activities up front, at the beginning of the run cycle. As the work scope for the next outage is formulated, clear and understandable retest requirements for the penetrations can be made, based on the penetration's health. If a good performer, a retest may only include a diagnostic test that confirms adequate valve seating to the as-left condition. A bad performer may require an LLRT following minor maintenance.

Some observations: The BWROG VTRG position paper suggested that the closing thrust be repeatable to within 10%. This was an effort to get the thrust as close as possible to the as-found condition. Combining all the history pieces together, and assessing whether the penetration was a good performer or bad performer, was key. Also, as the MOV test program matured, MOVs were being periodically tested to the same thrust windows. LLRT data collected in concert with MOV test data concludes a good performing penetration assembly need not be "locked" to the 10% criteria. Conversely, a review of data on a poor performing penetration would make any change in thrust, up or down, suspect.

It should also be noted that this approach does not recommend extension of the 60-month test interval by engineering analysis. Performing an analysis or alternate test is unacceptable, as the as-found test provides clear and objective evidence of performance of the penetration's isolation components.

Conclusion

By utilizing data inputs from established station programs, Appendix J owners can make a reasonable assessment to justify an extension of the LLRT test to the next available test window. Consideration for test results from MOV (AOV) diagnostic test equipment can be used to justify that the valve can perform its intended function, after minor maintenance.

The object of this programmatic review is to provide reasonable assurance the valve and penetration will perform its intended function until the next as-soon-as practical test opportunity. If however after the analysis, there remains some doubt regarding the minor maintenance activity's affect on the penetration, an as-found/as-left test provides clear and objective evidence of performance of the isolation components.

Enclosures:

1. Excerpts from BWROG CTRG task 95-07, page 1, 2 and Attachment 1, 4
2. Performance review example of Penetration 92(o) at Millstone Unit 3
3. Performance review example of Penetration 26(o) at Millstone Unit 3

TASK 95-07

Appendix J/GL89-10 Correlation
BWROG VTRG Committee Position

Retest Requirement Guidelines for Appendix J Valves

PURPOSE:
The purpose of this Document is to provide consistent Local Leak Rate Test (LLRT) retest guidelines to meet the requirements of 10CFR50, Appendix J for manual valves, Air Operated Valves (AOVs), Solenoid-Operated Valves (SOVs) and Motor Operated Valves (MOVs). Also provided is the methodology to provide sufficient justification to implement LLRT test interval extensions allowed by Option B to Appendix J.

BENEFIT TO LICENSEES:
Utilities can minimize redundant engineering evaluation and testing efforts associated with regulatory LLRT requirements by coordinating GL89-10 and 10CFR50, Appendix J provisions. Such coordination can avoid unnecessary levels of safety.

DISCUSSION:
In many cases, the rationale to justify performance (or non-performance) of a LLRT, if maintenance on a LLRT valve is performed during an operating cycle, has been found to be inconsistent from Utility to Utility and even from unit to unit within the same utility. Therefore, Attachments 1 through 9 have been developed to provide consistent guidelines for determining requirements for LLRT.

In addition, review of Rev. 0 of NEI 94-01, "Industry Guidelines for Implementing Performance-Based Option of 10CFR50, Appendix J" (dated 7/26/95), concludes that any licensee who elects to defer LLRTs must provide sufficient justification (See Annex A - NEI 94-01). This document is intended to supplement Annex A in justifying adjustment to the LLRT frequency.

- Attachment 1 can be used during development of the Work Order to determine if an LLRT is required. Engineering review of the retest requirements is necessary to defer LLRT testing.

- Attachments 2-6 provide additional guidance in cases of repacks, torque switch adjustments (for MOVs) and limit switch adjustments (for MOVs and AOVs). When using alternate diagnostic testing as a basis for LLRT deferral, a review that assures the valve and actuator have not undergone any severe environmental or overthrust event(s) since the last LLRT, should be documented.

TASK 95-07

Appendix J/GL89-10 Correlation

BWROG VTRG Committee Position

The basis for the majority of the recommendations are as follows:

- For gate valves, a change in the total available total closing force of less than 10% since the previous leak test, is considered to be within the accuracy of the diagnostic test equipment and a Type C Leak Rate Test would not be required. The closing force is essentially the same. However, significant (>10%) increase or decrease in available closing thrust could allow the disc to seat in a slightly different location and the sealing surface may be different, possibly affecting leakage rates. In these cases, Attachment 6 should be reviewed for applicability.

- Similarly, if the AOV spring tension is set to the same value as previously set, a Type C Leak Rate Test would also not be required since the closing force is essentially the same as the closing force during the previous leak test. Increased closing force on a globe valve could only increase the contact force between the seat and the plug (same seating surface) which would lead to a tighter seal. Therefore, as depicted in the Attachments 1-6, the Appendix J Type C test would not be required.

The NEI 94-01 guidelines recommend component design, safety significance of the penetration, cycle frequency of the valve, flow rate and fluid type, line size and service pressure be considered when extending/adjusting a service interval. These items, as well as the LLRT leakage/MOV(AOV) thrust data correlation over the last two or three test cycles, should be included in any technical justification developed for interval extension.

The NRC has endorsed the use of NEI 94-01 per NUREG 1.163, dated September 1995, with the exception of deferring as-found LLRTs. If maintenance or repair work is planned for a component, an as-found LLRT would be required. Performing an analysis or alternate test is unacceptable, as the as-found test provides clear and objective evidence of performance of isolation components.

Principle Investigators:

W. A. Loweth	G. E. McGovern
Millstone Unit 1 Tech Support	NNECo Programs Engineering

April, 1996

TASK 95-07

Appendix J/GL89-10 Correlation

BWROG VTRG Committee Position

ATTACHMENT 1

POST MAINTENANCE LLRT GUIDELINES

Maintenance activities identified below typically are not allowed an option to evaluate whether or not a LLRT is required. However, there are special circumstances, which should be evaluated on a case-by-case basis.

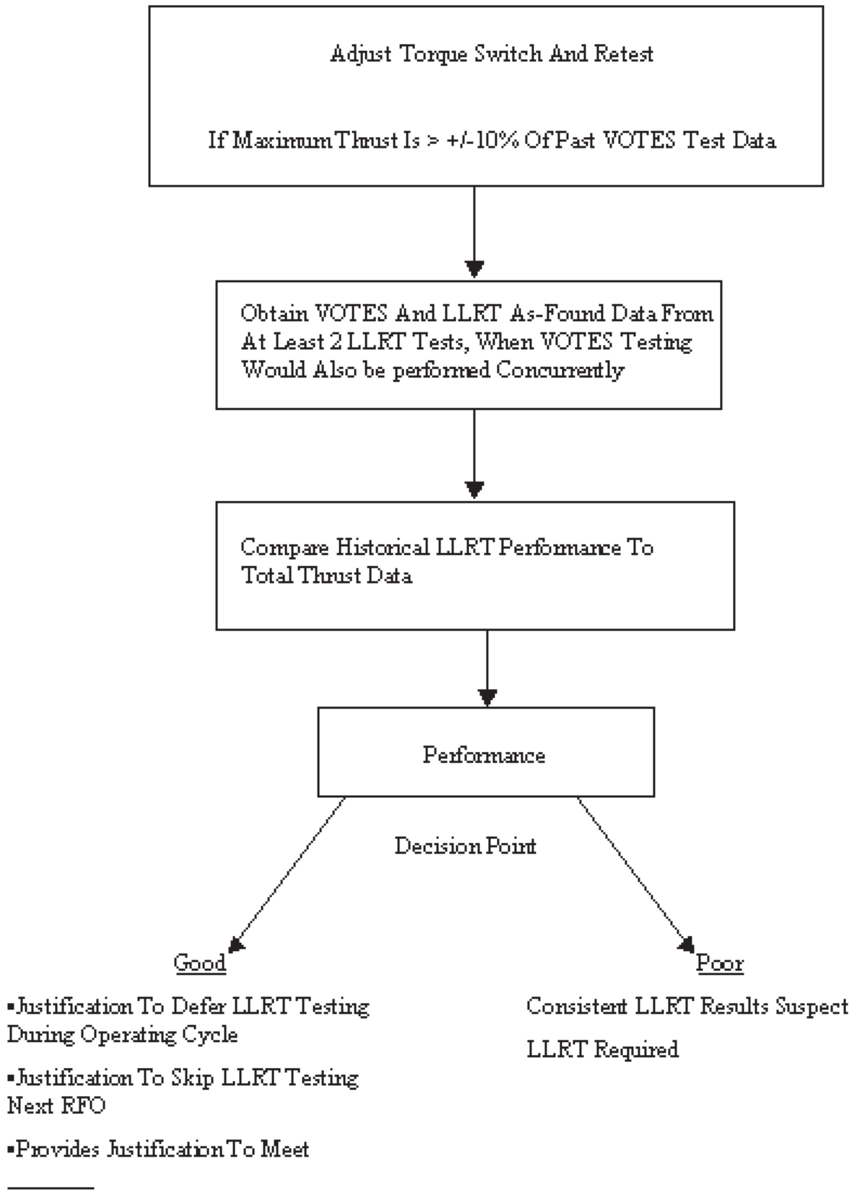
Maintenance Activity	Valve Type	Post-Maintenance LLRT Required	Comment
1. Solenoid valve removal or replacement (control air to actuator)	AOV	NO	IF AOV is air assist to close, air function must be verified in maintenance plan.
2. Disconnect Instrument Air Lines	AOV	NO	Same as No. 1.
3. Actuator diaphragm removal or replacement. (Actuator not removed)	AOV	NO	Assumes diaphragm is opening mechanism.
4. Spring Preload Adjustment	AOV	See Attachment 4.	
5. Valve diaphragm removal or replacement	AOV, Manual	YES	
6. Actuator removal or replacement.	AOV, MOV, SOV	YES	
7. Disconnect electrical leads	AOV, MOV, SOV	NO	Must verify stroke test is acceptable.
8. Cleaning and replacement of stem grease.	MOV,	NO	
9. Addition of grease to dry stem.	MOV	See Attachment 4.	
10. Overhaul valve internals, i.e., lap seat, change plug, disc or cage, pin replacement.	ALL	YES	
11. Remove or replace Starting coil.	SOV	NO	
12. Motor removal or replacement.	MOV	NO	
13. Stem nut removal or replacement.	MOV	See Attachment 4.	
14. Motor starter contactor replacement.	MOV	See Attachment 4.	
15. Clutch lever removal or replacement	MOV	NO	
16. Packing Adjustments	All	See Attachment 2,3	
17. Limit Switch Adjustment	AOV, MOV	See Attachment 5.	

TASK 95-07

Appendix J/GL89-10 Correlation
BWROG VTRG Committee Position

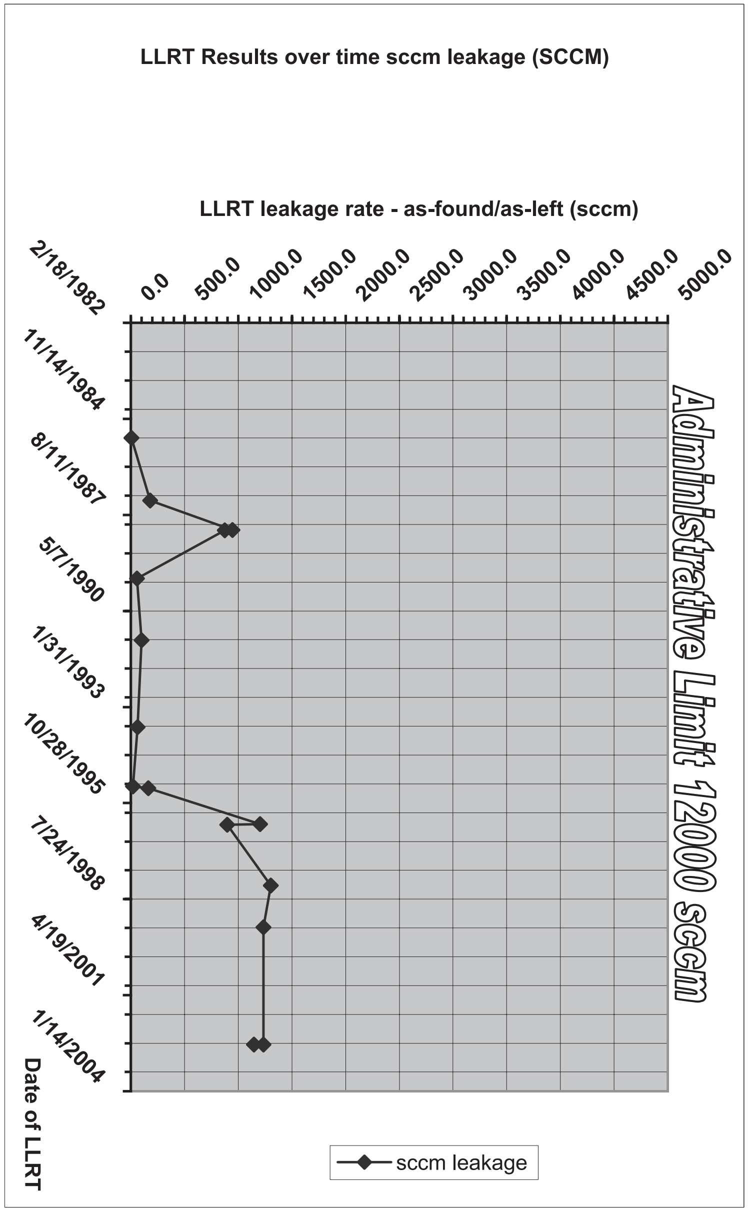
ATTACHMENT 4

POST MAINTENANCE LLRT GUIDELINE



Example of available data utilized to assess the "health" of a penetration

Penetration 92 (o) 3RHS*MV8701A 12" Gate Valve



(SBD-3, regeared from 76.26 to 43.9 OAR - 1997)

Westinghouse Flex wedge regear with new spring pack

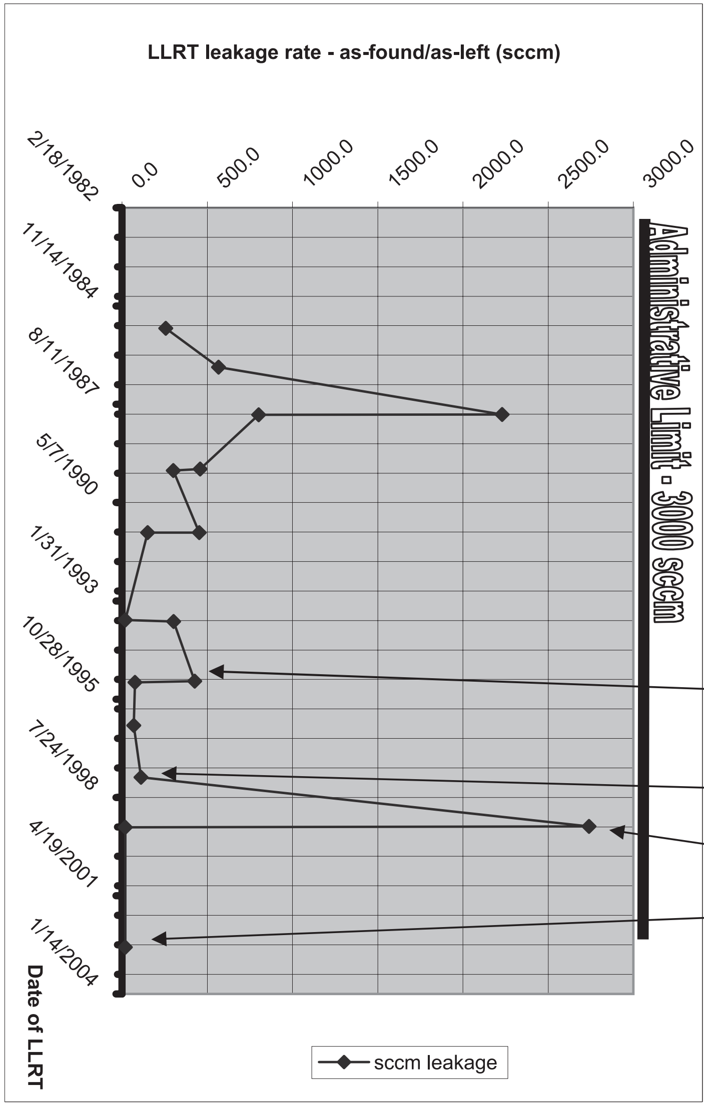
Date	AWO #	Work Performed	
5/28/1995	m39419688	actuator O/H Melamine TS repl.	
5/23/1995	m39419688	actuator replacement QSS installed	
9/15/1995	m39520747	TS byp installation	
6/7/1996	m39572791	PL mod to stuffing bax	
6/719/1996	m39607132	removed/replaced motor	
6/8/1996	M39608501	Removed packing- repacked	
6/13/1996	m39608545	VOTES test and packing retorque	
12/27/1997	m39704929	GL89-10 Act re-gear mod	
3/6/1998	M39803225	Stem nut replacement	93625 lbs TT AL
9/17/2002	m30005121	VOTES test and PM	73179 lbs TT AF 71294 lbs TT AL 9/16/02

ENCLOSURE 2

Example of available data utilized to assess the "heatlh" of a penetration assembly

Penetration 26 (o) 3CHS*MV8105 3" Gate Valve (was an SMB-00, replaced w/ SB-0)

<u>Graph of LLRT perfomance over a time period 1982-2002</u>



<u>History review of work activities on penetration 26(o)</u>

3CHS*MV8105 is solid wedge Crane gate valve - New Stem/stemnut added during conversion to a Limitorque SB-0-25 during recovery, circ, 1998 (was a SMB-00-25)

Date	AWO #	Work performed	
4/1/1991	m39104980	replaced melamine torque sw	
4/1/1991	m39104981	VOTES test TS set to 1.25 op/cl	
8/18/1993	m39305500	installed new packing	
8/29/1993	m39310430	operator rebuilt VOTES test w/SRI-2 grease	
8/18/1993	m39317317	Yoke Replacement, relub stem, retest SP	
8/29/1993	m39310430	VOTES test w/ new SP	
5/4/1995	m39417344	repack	
5/14/1995	m39504188	VOTES test TS to 2.875	
5/5/1995	m39507276	replace yoke bolts	
2/6/1998	m39713398	Stem, actuator and packing chg'd regear, QSS inst, EPO grease chg	
3/6/1998	m39803527	packing leak, packing drag 835 lbs before, 1566 lbs after	
5/27/1999	m39806655	repack after LLRT and reVOTES M39814277	AL 20522 lbs TT
9/20/2002	m39907197	SS wedge replacement and static test	AF 21458 lbs TT
			AL 20360 lbs TT

ENCLOSURE 3

APPENDIX J OWNERS GROUP {APOG} ISSUES

Wendell Brown, *Duke Power*

Jim Glover, *GRAFTEL Incorporated*

Gregg Joss, *Rochester Gas & Electric-Ginna Station*

Abstract

This paper formally introduces APOG to the nuclear industry following its formation in 2003 and provides an overview of the issues currently being addressed by the interim APOG Steering Committee (SC). The issues were selected based upon consensus opinion of the Appendix J program owner attendees at the inaugural Appendix J and Inservice Testing {IST} program owners information exchange meeting held in Scottsdale, Arizona June 9, 10 and 11, 2003.

Introduction

The success stories of various Owners Groups in the nuclear industry are well documented. These groups are self-motivated and take on the task of providing technically sound and cost effective solutions to various regulatory and commercial issues related to plant safety, component reliability and program cost reduction. However, for far too many years, the open exchange of experience and information regarding implementation of 10 CFR Part 50, Appendix J, between individual nuclear power plant Appendix J program owners was essentially non-existent. APOG was created to fill that information exchange gap and to provide a forum to develop industry consensus positions for issues considered key to the general membership of APOG.

APOG employs a website {WWW.APPENDIXJ.COM} to facilitate the exchange of information. Website features include posting of Appendix J questions and queries, access to numerous industry Codes, standards, regulatory documents and industry papers, the capability to conduct information surveys, and an "Ask the Expert" feature hosted by

Jim Glover, the Chairman of ANSI/ANS 56.8 and President of GRAFTEL Inc., APOG's facilitator. Use of the website in conjunction with regularly scheduled SC conference calls, allows APOG to accomplish tasks that traditionally were reserved for working group sessions at regularly scheduled owners group meetings. The corresponding reduction in member travel costs, meeting venue fees, and increase in efficiency realized by employing group discourse via the website and teleconferences, results in a very low annual group membership fee, a welcome relief given today's utility economic picture.

Issues Currently Being Addressed

ISSUE # 1:

Regulatory Guide 1.163, Regulatory Position C 2, endorses a 30 month prescriptive Type C test interval as specified in Section 3.3.4 of ANSI/ANS-56.8-1994 for Containment purge and vent valves regardless of the valves' size (diameter). APOG is developing a technical position {TP} that will define the limiting valve diameter. The intent of the TP is to allow valves having a diameter less than or equal to the limiting diameter to be eligible for performance based Type C test intervals as per Nuclear Energy Institute (NEI) 94-01, section 10.2.3.2.

ISSUE # 2:

The "As-Found" testing requirement delineated by NEI 94-01, is not clear regarding applicability to components which are on a fixed, 30 month prescriptive test interval, versus those on extended intervals (up to a maximum of 60 months). APOG is developing a TP which will define the as-found test requirement applicability for all Appendix J program components.

ISSUE # 3:

The allowable test interval extension period guidance delineated by NEI 94-01 is inconsistent between sections 9.1 and 11.3. APOG is developing a TP that will state under which conditions the 25 % tolerance (up to a maximum of 15 months) applies to Type A, B, C test intervals.

ISSUE # 4:

The issue of boiling water reactor (BWR) plants performing local leak rate testing (LLRT) of their main steam isolation valves (MSIV) with actuating air being applied during the LLRT has been a significant regulatory compliance topic. APOG is developing a TP which will provide guidance on a test methodology which will ensure that leakage through these components is adequately assessed for the design basis event under credited system operating conditions.

Once the APOG SC approves these TP's, APOG will issue them to its members for potential inclusion in their program using the 10 CFR 50.59 review process for all associated changes. In addition, APOG may choose to employ a Topical Report submittal of these technical positions to the NRC.

Conclusion

With APOG still in its infancy, it has gained momentum rather quickly by taking on meaningful issues which can yield significant financial and regulatory compliance benefit to Appendix J program owners. The APPENDIXJ.COM website has been a very active vehicle with over a thousand visits by members and guests posting questions, providing answers and informational feedback, downloading information from the technical library, locating member contact information, etc.

APOG membership is increasing daily and it appears that by the end of 2004 greater than 60% of the operating plants will be active members. By encouraging the NRC, Institute of Nuclear Power Operations (INPO), and NEI to be regular participants in the general sessions of APOG, the establishment of a regular venue for ongoing dialogue will be realized. The benefits of such dialogue include enhanced regulation application guidance and compliance as well as improvement to existing or creations of new, better-informed regulations.

In addition to the regulatory aspect of APOG, the sharing of information and experience between members will result in tangible savings tied to dose reduction, outage duration reduction, increased component reliability with the need for less corrective maintenance, and test methodology and test hardware improvements.

APOG looks to follow in the footsteps of its many successful owners group predecessors by remaining active and contemporary in all Appendix J related matters and issues. The success path involves committed utility membership and active participation by regulatory personnel. For questions about becoming a member or being a regulatory interface to APOG, please contact: Gregg Joss, or Jim Glover/Brad Miller of GRAFTEL Inc.

NOTE:

At the time of this paper submittal, the TP's associated with Issues 1 through 4 above were not yet approved for distribution by the APOG SC. Handouts of the approved TP's will be distributed at the Session venue in advance of the paper being presented.

References

ANSI/ANS 56.8-1994, "Containment System Leakage Testing Requirements"

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